RIIO T1

nationalgrid

System Operator External Incentive Plan: Electricity

National Grid Electricity Transmission

May 2012

Target audience

All Stakeholders

About this document

This document sets out our System Operator incentive proposals for the RIIO-T1 period. It describes the operating environment against which the incentives are set and discusses how we will innovate to deliver best value for consumers. We explain how we will manage uncertainty and balance the risk for consumers. Where appropriate, stakeholder feedback on our proposals has been included.

This document is an edited version for all stakeholders of our submission to Ofgem on 31st May 2012 with confidential information removed.

Electricity System Operator Incentives Plan

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Executive Summary

1 National Grid Electricity Transmission (National Grid) undertakes the role of National Electricity Transmission System Operator (NETSO) for England, Wales and Scotland.

2 The regulatory framework within which the NETSO operates is under review in parallel to the ongoing price control reviews for all UK gas and electricity Transmission businesses. This will be the first review of the SO activity under the new RIIO regulatory framework model (Revenue = Incentives + Innovation + Outputs) where a new SO incentive framework will be established for an 8 year duration. The review commenced with Ofgem's consultation on its initial views of the incentive principles from 2013 in June 2011[1] followed by the publication of a further consultation "System Operator Incentive Schemes from 2013: Principles and Policy" published in January 2012[2].

3 The framework that we propose in this plan includes cost and financial incentives that will drive us to minimise the external balancing services costs of operating the National Electricity Transmission System (NETS). The proposed package includes incentives around the delivery of services required to recover the NETS in the event of a partial or full system shutdown (Black Start). It also includes a financial incentive focussed on reducing transmission losses and a new incentive on the accuracy of the wind forecasts that we publish to the industry.

4 These schemes have been developed to take account of future uncertainty in the operation of the NETS, as conventional sources of generation are replaced with renewable generation and the level of interconnection with non-GB markets increases. These will create new challenges in operating the NETS against much more dynamic and uncertain generation and demand patterns, making it all the more important that appropriate incentives are in place to ensure the NETSO continues to deliver the level of service that customers and consumers depend upon.

5 These incentives are designed to promote innovation in the delivery of key outputs valued by customers, to ensure we remain focussed on the efficient and economic operation of a safe and reliable NETS, and to deliver value to consumers. The full set of proposed incentives are summarised in the table below:

[1] Ofgem's consultation on System Operator Incentive Schemes from 2013 is available on the Ofgem website.

[2] Ofgem's consultation on System Operator Incentive Schemes from 2013: Principles and Policy is available on the Ofgem website at http://www.ofgem.gov.uk.

Proposed Incentives

Cost incentives	Financial incentives
Balancing Services Incentive Scheme: Energy Components, Constraints and Black Start	Transmission Losses
	Renewable Generation Forecasting
	Customer & Stakeholder Satisfaction

6 These incentives are distinct from, but complementary to, the funding of our internal costs of operating the NETS, which are covered in the System Operator Annex of our March 2012 RIIO-T1 Business Plan submission[3].

7 A more detailed overview of the schemes that we propose is set out in the table below.

Overview of proposed System Operator Incentive Schemes

<table>
<tr><th>Scheme</th><th colspan="4">Key features</th></tr>
<tr><td rowspan="4">Balancing Services Incentive Scheme (BSIS)</td><td>Length</td><td>Scheme Phase dates</td><td>Annual Cap/ Collar</td><td>Annual Sharing Factor</td></tr>
<tr><td>2</td><td>Apr ’13 – Mar ‘15</td><td>± £30m</td><td>30%</td></tr>
<tr><td>2</td><td>Apr ’15 – Mar ‘17</td><td>± £40m</td><td>40%</td></tr>
<tr><td>4</td><td>Apr ’17 – Mar ‘21</td><td>± £50m</td><td>50%</td></tr>
<tr><td>Energy Components</td><td colspan="4">• Subject to the above BSIS parameters
• Reassessment of the ex ante or ex post treatment of model inputs
• Enhanced cost target models which should more accurately represent the drivers of operating costs over the RIIO-T1 period
• Proposals to further review and develop the suite of models over the 8 year period</td></tr>
<tr><td>Constraints</td><td colspan="4">• Subject to the above BSIS parameters
• Enhanced cost target models which should more accurately represent developments to the NETS over the RIIO-T1 period
• Reassessment of the ex ante or ex post treatment of model inputs
• Introduction of an uplift factor applied to target model output to account for modelling shortfalls
• Proposal to align the NETSO and TO incentives for constraint costs associated with networks outside of the England and Wales footprint</td></tr>
<tr><td>Black Start</td><td colspan="4">• Subject to the above BSIS parameters
• Cost target derived from a number of assumptions for both new &</td></tr>
</table>

[3] The System Operator annex of our March 2012 RIIO-T1 Business Plan submission can be found on the National Grid website at http://www.nationalgrid.com

	existing station costs • Annualised new entrant cost of [text deleted] with downward adjustment for legacy contracts • Ex ante assumptions for annual feasibility studies and testing costs
Transmission Losses	• Subject to the above BSIS parameters • Ex ante target based on previous year outturn with ex post adjustment • Ex post adjustment to the target using Transmission Loss Factors and ex post generation and demand patterns • 20% sharing factor
Renewable Generation Forecasting	• A new financial incentive to reduce day ahead wind forecasting error • Introduction of regional forecasts and an increase to four national forecasts per day • A cap/ collar of +/-£250k per month • 4+4 year scheme, with mid point review
Customer & Stakeholder Satisfaction	• Proposed customer satisfaction incentive on National Grid to include the SO role • Value up to +/-1% of annual TO revenue • Maximum 0.5% of annual TO revenue as a discretionary award

8 We have engaged with our stakeholders and sought their views on the SO incentive proposals that we have developed. Their views have been used to shape this plan, and we have included a new incentive in the areas that customers have indicated would be of value, in particular around renewable generation forecasting.

9 These proposals have been developed to be consistent with the principles set out in Ofgem's January 2012 consultation, together with the views expressed by ourselves and other stakeholders in response to that consultation. We have created a longer-term incentive framework, where schemes are designed to operate on an annual basis, with annual targets, caps/ collars and sharing factors. Adjustment mechanisms are used where appropriate to set targets against future uncertainty.

10 Where incentives are new, or where we believe incentive targets could become inaccurate over a longer timeframe given the uncertainties we face, we have proposed that incentive methodologies are reviewed periodically to ensure they remain focussed on the outputs valued by customers. We have sought to align sharing factors with those set for internal costs under RIIO-T1 where outputs are clearly understood, forecastable & controllable. We have retained the use of caps and collars where appropriate, to protect ourselves and consumers against windfall gains or losses resulting from factors outside our control. We also propose to retain the concept of Income Adjusting Events to manage low probability and high impact events that are outside of our control that cannot be foreseen when allowed revenues under the incentive scheme are set.

11 Finally, the incentive schemes will be captured by a number of uncertainty mechanisms around significant policy changes, such that if these are

triggered, it may be necessary to reopen related incentive schemes presented in this submission.

12 Over the RIIO-T1 period, evolution in the energy market may present new opportunities for SO incentives, particularly if new products or services are developed that are valued by our customers. We propose that the incentive framework is sufficiently flexible to accommodate new incentives over the RIIO-T1 period such as those associated with other types of renewable generation or with Electricity Market Reform (EMR).

13 These incentives are designed to provide financial reward for the delivery of outputs over and above the baseline level set by the incentive targets, and a financial penalty for under performance. However, inherent in these schemes is a range of underlying financial risk that is outside of our direct control. The SO does not have a sufficiently large balance sheet to underwrite this risk, and therefore this incentive risk is effectively underwritten by the wider National Grid balance sheet. Although this risk could be funded via a premium to the allowed return on equity for National Grid's transmission business, we propose that this risk is funded via an ex ante risk premium of circa £8m per annum included within the incentive package.

14 The schemes proposed in this plan aim to represent a fair balance of risk and reward and operate in the interests of consumers. Given the uncertainty we face going forward, with fundamental changes to energy markets in the UK and across Europe, it is all the more important that strong incentives remain in place to ensure our interests and those of consumers remain fully aligned.

15 We look forward to engaging further with Ofgem and the wider industry during the consultation process.

Document Structure and Next Steps

16 This document sets out our proposals for our electricity SO external incentives. The first sections of this document discuss the changing SO role over the RIIO-T1 period and the overarching principles applied in developing the SO external incentives before exploring specific proposals for each SO incentive output in detail.

17 The sections for each output provide a brief summary of the current regulatory framework, the expected developments over the RIIO-T1 period including interactions with the TO activity, the risk and uncertainties and our proposed approach. Some sections have further analysis and information provided in appendices to support our proposals.

Our Consultation Process

18 We have engaged with our stakeholders, discussed our proposals and heard their views as to which incentives are of value to them. This has included workshops, meetings, a written consultation and the work previously carried out in relation to the development of our RIIO-T1 business plan. Specifically, we have listened, discussed and acted on stakeholders' views received via our consultation on specific incentives and have reflected them in the development of this plan. For ease of reference, we have highlighted these areas of our plan with the speech marks symbol in the left margin.

Next steps

19 In June 2011, Ofgem stated its aspiration to lead the development of the SO Incentives for the RIIO-T1 price control review. To inform this process, this document sets out our SO external incentive plan for the 8 years from April 2013.

20 Following our submission of this plan, Ofgem will consider and develop Initial Proposals for this summer and Final Proposals by the end of 2012.

Supporting Information

21 This plan should read in conjunction with the following documents on the National Grid website:

(a) **BSIS Methodology 2011-13: Treatment of Modelling Inputs**
Treatment of Modelling Inputs Methodology

(b) **BSIS Methodology 2011-13: Modelling Energy Costs**
Modelling Energy Costs Methodology

(c) **BSIS Methodology 2011-13: Modelling Constraint Costs**
Modelling Constraints Cost Methodology

Contact details

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

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23 To register your interest in receiving future communications on SO incentives please email: SOIncentives@nationalgrid.com.

24 The dedicated web pages for this incentive review process are available at the following address: National Grid: Electricity SO Incentives

The System Operator Role: Now and into the future

Overview

25 This section outlines our role as the National Electricity Transmission System Operator (NETSO) and the activities we undertake in balancing the National Electricity Transmission System (NETS). It sets out the changes to the external environment in which we operate and the challenges that will arise in terms of the complexity, uncertainty and cost of system operation over the RIIO-T1 period.

26 We outline how we plan to evolve and innovate our strategies, tools and capabilities in order to meet the changing characteristics of demand and generation patterns along with the change in design and operation of the NETS in order to deliver the key outputs valued by our stakeholders whilst operating an economic, efficient and reliable transmission network.

The role of the NETSO today

27 Our principal role as the NETSO is to maintain the energy balance between generation and demand in an economic manner, whilst ensuring that this is achieved within the capability of the network. The ability to forecast system conditions and manage the risks inherent in operating a complex power system is vital to ensuring safe, secure and efficient system operation.

28 More broadly, our role requires us to:

(a) Co-ordinate power flows across the transmission networks in accordance with the relevant security and quality of supply standards

(b) Maintain the continuous balance of electricity generation and demand consumption in real-time across the network as a whole

(c) Manage system operation costs through the efficient procurement of services via the balancing mechanism or through the procurement of ancillary services; and

(d) Facilitate the market through the publication of data and the administration of the supporting regulatory codes

29 Through these activities we seek to deliver value to our stakeholders and the required level of service to our customers.

“We believe that National Grid should deliver network reliability consistent with its licence and that minimises customer minutes lost.”
RWE Power, May 2011 consultation response

30 The key elements of our role as NETSO are detailed fully in our March Business Plan for the RIIO-T1 period[4].

The changing nature of our NETSO Role

31 In 2005, our system operator role was expanded to cover the whole of Great Britain via the introduction of British Electricity Trading and Transmission Arrangements (BETTA)[5]. In 2009, our Great Britain (GB) System Operator role was expanded further to cover offshore transmission networks. These changes have affected the way in which we operate the system and the associated cost drivers.

32 During the RIIO-T1 period, the operation of the NETS will fundamentally change, moving from a relatively predictable generation and demand base to one that includes a significant volume of renewable generation with more variable output, and greater interconnection with Europe. This fundamental change in the generation background will increase the complexity of managing the system as power flows across the network become more variable. In addition, demand will become more flexible and responsive with the use of new technologies to promote greater demand-side management, including the introduction of smart meters across GB, which will help support the increased variability in generation. Towards the end of the RIIO-T1 period, new technologies such as electric vehicles will begin to fundamentally change the characteristics of demand.

33 The design of the NETS will also change significantly, not only as a result of the changing energy mix, but also as a result of investment in new capacity, new SmartGrid technologies, new network topologies (e.g. offshore HVDC links), the development of offshore transmission networks and the impacts of policy changes such as the connect and manage[6] regime. This will change the dynamics of the system and impact on system constraints for a period of time prior to and during construction of the transmission infrastructure needed to support our low-carbon energy future.

34 These new challenges will make the task of operating the transmission system more complex. In order to ensure the current levels of system reliability are maintained, it is inevitable that operational safety margins will need to increase to deal with growing supply and demand uncertainties. Maintaining current levels of system reliability against a more variable and unpredictable pattern of generation and demand will inevitably place upward pressure on balancing services costs.

35 The next decade will see a period of uncertainty in which costs will see upward pressures as we handle connect and manage, deal with major transmission investment programmes, and go through a period of market change. However, as the NETSO, we have a real opportunity to develop new operational capabilities, innovative tools and commercial strategies to manage

[4] RIIO-T1 Proposals – Electricity Transmission

[5] BETTA expanded the market wholesale trading arrangements to include Scotland to create a single balancing market.

[6] Connect and manage is where generation projects are allowed to connect to the transmission system in advance of the completion of the wider transmission reinforcement works. National Grid: Policies and Guidance

this uncertainty and deliver ongoing value to stakeholders and consumers in operating a secure, reliable and efficient transmission system.

The challenges faced

36 The external environment within which we carry out our NETSO role will change substantially over the RIIO-T1 period with:

(a) Decarbonisation of electricity production;

(b) Transmission network reinforcements;

(c) Demand-side management;

(d) Smart grids and distribution networks; and

(e) European interconnection and market harmonisation.

37 Broadly the impacts will fall into four areas:

(a) An increase in balancing activities due to variable output from wind generation, interactions with other European markets via interconnectors and more dynamic demand patterns;

(b) An increase in the level of operating reserve needed to maintain system frequency for an increase in the largest unit connected to the system and the increased variability of generator output;

(c) An increase in system complexity as we operate new transmission assets including offshore networks and more sophisticated technologies that are being installed on the network to maximise network capacity; and

(d) An increase in transmission constraint volumes experienced while network infrastructure is built to accommodate new, low-carbon generation.

"In the future National Grid's network will need to connect renewable generation on the periphery, ensure reliability is maintained across the UK network for its end users, extend the GB network out into an integrated European network and will need to accommodate a smarter physical network."
Stage one workshop Brunswick report, 19th January 2011

38 These are discussed in further detail below.

Decarbonisation of electricity production

39 The NETS will change over the next decade as the generation of electricity is decarbonised. During this period ~17GW of coal and oil plant will be closed, mainly driven by the European Large Combustion Plant Directive (LCPD), to be replaced with a large increase in wind generation[7], new gas generation,

[7] Much of it in Scotland and offshore connected at the periphery of the system

Combined Heat and Power (CHP), solar power and other generation types embedded in the distribution networks. New nuclear generators, increasing the maximum single infeed loss, may also commission towards the end of this period. This shift in the nature and location of electricity generation will fundamentally change the challenges faced by the NETSO.

40 The output of renewable generation, mainly from wind farms, is more variable and less predictable than the output from conventional thermal generation. When renewable generation is not available, this will generally have to be replaced with conventional generation located elsewhere on the network. As a result, the volume of reserve and response sourced from conventional generating plant needed to maintain system frequency will increase.

Transmission network reinforcements

41 As outlined in our July and March RIIO-T1 Business Plan and supported by our stakeholders, the NETS will need to be adapted and upgraded to support electricity flows associated with the installation of new generation.

“” *There is a need for more flexible networks and smarter networks.*
Student event Brunswick report, 13th April 2011

42 The development and reinforcement of the NETS will have a direct impact upon our role as NETSO. System access will be required for the construction and commissioning of new assets, which will have an impact upon system capability and constraints. Tighter construction schedules are likely to lead to increased system outages requirements and therefore reduced network availability, all of which will place upward pressure on constraint costs while this construction is underway.

Demand side management

43 Electricity suppliers have an obligation to source an increasing proportion of the electricity they supply to customers from renewable sources and are incentivised to balance their contracted positions. With increasing wind output variation, suppliers may choose to balance their position via more use of Demand Side Response (DSR), rather than deploying short notice generation. Over the RIIO-T1 period, a larger proportion of demand will be settled using half-hour metering as the domestic and small commercial market move to smart metering and become more price sensitive. This is likely to influence the way that we deploy reserve capacity and balance the system.

44 Increased consumer price sensitivity and greater demand flexibility enabled through new technologies will provide further challenges to system operation, but will also offer opportunities to develop new demand-side strategies, tools and contracts to operate the system efficiently.

Smart Grids and distribution networks

45 The nature of operation of the Distribution Network Operators (DNOs) will change, with more distributed generation (wind and CHP) and micro generation such as photovoltaic solar altering power flows across the distribution networks. Rapid adoption of electric vehicles and electric space

heating will increase demand dramatically and is likely to do so initially in hot spots within distribution networks.

46 In response to these changes, smart network initiatives may see more interconnection between grid supply points and more local dispatch by DNOs to control local power flows across distribution networks. These changes will have an impact on the demand being supplied by the transmission network at the boundary which, in addition to other demand side actions, will need to be factored into the way the system is balanced.

Market change including Electricity Market Reform (EMR)

47 DECC published its Electricity Market Reform (EMR) white paper[8] in July 2011 setting out changes to the UK's electricity market to ensure that future electricity supply is secure, comes increasingly from low-carbon sources and is affordable. There are four key elements of the reform package including:

(a) The introduction of a Capacity Mechanism (CM) to ensure future security of supply

(b) The introduction of new long-term contracts: Feed in Tariffs with Contracts for Difference (FiT CfD)

(c) An Emissions Performance Standard (EPS) set as an annual limit equivalent to 450g CO_2/KWh; and

(d) A Carbon Price Floor (CPF) to reduce investor uncertainty, as announced in the 2011 budget

48 In December 2011, DECC published a technical update which included the Government's view that the system operator is best placed to administer and deliver the EMR functions of the Capacity Market and the FiT CfD. The Energy Bill[9] published on 22nd May 2012 establishes this role as part of the EMR institutional arrangements.

49 The details concerning the role are yet to be finalised but we envisage that the implications will join others from a continuing stream of policy driven changes that result from GB and EU legislation, licence and code changes.

European interconnection and market harmonisation

50 There will be an increasing level of interconnection with Europe, increasing from the present 3GW to 7GW by 2020 in the Gone Green scenario and leading to potential swings in electricity flows of up to 14GW. This means network electricity flows will be increasingly subject to the interactions between European market hubs as these address emerging supply and demand needs. As well as shifts between import and export, power flows may also pass through GB as markets address congestion on other European borders or as energy transits through GB to/from Ireland. To facilitate the

[8] Electricity Market Reform White Paper 2011 - Department of Energy and Climate Change
[9] Energy Bill - Department of Energy and Climate Change

European market, flows on interconnectors will only be limited by non-market means under the most onerous conditions.

51 In response to these evolving changes we have helped establish CORESO[10], a regional security coordination organisation, with neighbouring Transmission System Operators (TSOs), to manage security issues across national boundaries. As the level of interconnection with Europe increases, the role and the footprint of this entity will need to be developed to ensure that the impact of interconnector flows on the network can be managed as inter-region energy transfer dependencies increase and are codified into standard European Network Codes.

52 EU driven regulatory changes during the RIIO-T1 period will have a direct impact upon the GB market. However, at this stage it is unclear what impact this will have upon the electricity regime and the codes[11]. It is likely that such changes could include significant changes to licences, codes, processes, IT systems and commercial arrangements.

Adapting to the operating environment

53 Our challenge as the NETSO will be to ensure the ongoing safe, reliable and efficient operation of the NETS in our changing environment. We will continue to work closely with our stakeholders and customers, listening to what is important to them and developing policies and services which will deliver value to them through this uncertain period. We will achieve this through developing innovative new tools and techniques, new capabilities and processes to handle an increasingly complex task. The SO incentives proposed in this submission are designed to ensure that the NETSO continues to deliver value against this very uncertain future; that it remains absolutely focused on the key outputs valued by its customers and the end consumer.

[10] http://www.coreso.eu/

[11] Balancing Settlement Code (BSC), Connections and Use of System Code (CUSC), System Operator – Transmission Owner Code (STC) and Grid Code

System Operator Incentives and the overall Transmission Service

Overview

54 This section describes the role and purpose of National Electricity Transmission System Operator (NETSO) incentives as a key mechanism to support the delivery of consumer benefits particularly while the UK's transmission infrastructure is being upgraded to support the development of an affordable, sustainable, low-carbon energy sector.

55 Our activities are part of the overall package in delivering a complete transmission service to customers across Great Britain, both as an integrated Transmission System Operator (TSO) across England and Wales, and in partnership with the Transmission Owners (TOs) in Scotland and offshore.

Challenges in delivering the overall Transmission Service

56 In seeking to develop RIIO-T1 proposals for our total transmission activities, we have been mindful of the need for a joined up approach to delivering an overall transmission service. This has been particularly challenging given that the requirements for this service are subject to unprecedented change, including:

(a) New policy priorities (especially for environmental sustainability but also with new focus on security and affordability);

(b) New markets arrangements (delivering national policy objectives and those for integrating European energy markets);

(c) Exceptional change in the sources of generation and nature of demand, leading to very different power flow characteristics;

(d) New network topology and geography (due to offshore connections and new interconnectors);

(e) New network technologies and control opportunities (often collectively referred to as 'smart'); and

(f) Heightened requirements to achieve public acceptability and financial viability.

57 In terms of our network, we have presented a compelling case for substantial investment in transmission infrastructure in order to maintain the economic and efficient delivery of a reliable transmission service, whilst expanding the network and significantly increasing network capacity to accommodate the expected growth in low carbon generation, offshore wind and increased interconnection with Europe.

58 In balancing the system across GB, stakeholders are already aware of trends towards higher balancing costs and, with the system in transition, the potential for further escalation.

59 Overall, we are aware that consumers are facing increasing transmission costs in real terms and increasing volatility in both transmission network and balancing service charges. Given the operational and network extension challenges ahead, it is important to keep the relevant regulatory, commercial and organisational frameworks under review to ensure the optimal and efficient delivery of transmission services in the best interests of consumers now and into the future.

60 More specifically, it is important that strong incentives are established that promote alignment between National Grid and the TO organisations to facilitate the required investment in transmission assets, whilst minimising the overall cost of delivering that investment, including the constraint costs resulting from the outages necessary to undertake this investment.

Delivering the 'Transmission Owner' Service Component

61 On delivering the overall transmission service, there are a number of key issues relevant to the Transmission Owner (TO) activities, including:

(a) Delivering investment required to upgrade and expand the transmission infrastructure across Great Britain;

(b) The introduction and use of "connect and manage" whereby customer connections are commissioned before deeper infrastructure has been completed – advancing the operation of new generation but increasing the risk of higher interim congestion/constraint costs;

(c) Industry based consideration of deeper infrastructure works, offering the opportunity to anticipate rather than only respond to user developments and financial commitments; and

(d) The focus under RIIO-T1 for transmission companies to lead the process of engaging stakeholders to identify required outputs and develop plans to deliver them.

62 It is essential that these challenges are met in a joined up, co-ordinated manner in order to avoid creating a barrier to efficiently meeting the challenges ahead.

Delivering the 'System Operator' Service Component

63 Our Operating in 2020[12] consultation and RIIO-T1 discussions on our NETSO activity have focused on the need to adapt and improve the control facilities and operational capabilities to meet emerging challenges. Key areas identified include:

(a) A focus on wind (and solar) output forecasting;

(b) Collaboration with other European system operators to co-ordinate control actions that influence loop flows and mutual support measures;

[12] Discussion of National Grid's current analysis and views on operating the electricity networks in 2020: National Grid: Consultation: Operating in 2020

(c) Greater use of new smart network technology opportunities to make real-time measurements of system utilisation and thermal capability with increasing automation to control flexible transmission devices and use services from generators and demand side providers; and

(d) Further development of risk management approaches to make best use of existing assets.

64 These areas require a particular focus on the interfaces between the system control facilities and the transmission assets. Existing design and operational practices may not be appropriate for the future and codifying existing practices may well risk barriers to innovation and unnecessary costs.

65 Again, it is essential we have a joined up, co-ordinated approach across NETSO and TO activities to ensure we maximise the benefits we can leverage from technology to deliver an efficient transmission service into the future.

System Operator Role and Incentives

66 The incentives deriving from System Operator exposure to external costs (as currently implemented in the Balancing Services Incentive Scheme) are a key element in aligning system operational decisions and the interests of consumers. The current form of the electricity system operator incentives, a sliding scale exposure to a range of System Operator costs, has been used since the first system operation incentive arrangements were negotiated bilaterally with suppliers in the mid-1990's.

67 These incentive schemes have proved extremely powerful in driving system operator decisions to optimise balancing costs in the short-term, as well as informing investment decisions to manage balancing costs in the longer-term. In the future, strong, focussed incentives on all aspects of the transmission service (NETSO and TO) will be vital to ensure the efficient delivery of this service, while the UK's transmission infrastructure is upgraded to support the development of an affordable, sustainable, low-carbon energy sector.

68 Key to the design of incentives is that they focus on outputs of the transmission service which ultimately deliver value for consumers, where these are outputs that can be controlled/influenced by National Grid and/or the TOs, and the associated costs subject to these incentives are appropriately funded.

69 The NETSO, with a holistic view of the costs incurred in balancing the system, driven by either its own actions, the actions of individual TOs in making network capacity available, and by other market participants/service providers is often best placed to manage many of these costs on behalf of customers. The range of NETSO incentives proposed in this submission is designed to align National Grid's interests with the needs of our customers and electricity consumers.

70 Further information regarding the incentive principles that underpin the development of the NETSO incentive schemes set out in this submission can be found in the 'SO Incentive Principles' section below.

Alternative approaches to System Operator Incentives

71 In considering our proposals, we have examined alternative approaches to system operation organisation and incentivisation, as discussed below:

The Gas Transmission Model

72 Different incentive 'pots' for balancing cost components of System Operator activity, which, for example, permits operator financial exposure to reflect the degree to which the costs are controllable.

The Independent System Operator (ISO) Model

73 ISO organisations, independent of generation, supply and transmission ownership, as exemplified by PJM in the US. Generally such system operators are not themselves exposed to balancing costs but provide despatch instructions consistent with specified equipment capabilities and calculate spot and transmission right prices which inform and incentivise the behaviour of market participants.

74 Although there is some scope for transmission owners to receive incentives from such signals, we understand that most transmission owners are separately regulated and incentivised on their specific outputs rather than their contribution to the overall service. The presence of an independent system operator provides a neutral environment for the competitive selection of transmission owners (see Chile, where this approach has been long established, and other South American countries).

European Approach

75 Across Europe, transmission system operators are subject to a range of incentives with varying exposures to internal network and external balancing costs.

76 The transmission arrangements relate to specific organisation and market models set out in European legislation. The 3rd package identifies the potential for using what is defined as an Independent System Operator model (including independence from network ownership) in cases where a utility was vertically integrated on 3rd September 2009. Such arrangements require such an ISO to undertake network investment planning, construction and commissioning although the eventual network ownership will lie elsewhere. We understand approval for these arrangements are being sought in Romania and Latvia.

77 Alternative models are to establish a fully ring-fenced Independent Transmission Operator (for example RTE in France) or a specifically derogated arrangement (such as that which we understand is being sought for Scotland). Otherwise all transmission companies are required to be ownership unbundled from generation and supply interests and responsible for the full range of transmission system operator activities which deliver third party access.

Role Objectives

78 Two aspects can be identified from the cases listed above:

(a) In some cases, evolution of the overall transmission service is a key objective. Here the system operator is an important agent in facilitating the evolution of energy markets, choosing between services from transmission assets or other service providers, integrating and meeting the requirements of new network users and adopting new technologies. In such cases, direct incentivisation of the system operator on the overall system outputs can be important in aligning network interests to those of consumers; and

(b) In other cases, efficient delivery of transmission assets is more the focus. Here the functional requirements for transmission assets must be transparent so providers can bring forward alternative satisfactory options.

Incentives for the NETSO role

79 From the earlier listing of needs and policy strands, both of these aspects are in play in the GB electricity transmission system:

(a) The need for significant innovation in the way new users are connected and integrated in the transmission system means that detailed codification of the system operator to transmission owner interface to address emerging needs is unlikely to be practical or beneficial at this time;

(b) Full internalisation of the costs of delivering the overall transmission service through system operator financial incentives (for example, with full system operator liability for the buy-back of capacity in the event of constraints/congestion in gas transmission) is also unlikely to be feasible or beneficial. With “connect and manage” the NETSO is generally unable to ensure transmission capacity could be established before it is allocated, and therefore full internalisation of the associated constraint costs would create excessive risks; and

(c) Also, separate ownership of transmission assets in Scotland, offshore and perhaps increasingly onshore in England and Wales means that the degree of control by National Grid will be much less than where asset ownership is part of the same organisation.

80 The options relevant to such a mix of arrangements might include a set of system operator external cost sharing factors that differ from the RIIO-T1 total expenditure (totex) exposure rate and also differ by external cost “pot” according to:

(a) The degree of control/discretion resulting from policy constraints (for example, reflecting the impacts of the connect and manage policy and the prohibition against providing congestion related price signals in the GB market);

(b) The degree of control/discretion resulting from asset ownership and the ability to innovate on the control/asset interface (with lower exposures where transmission assets are owned by other parties and the allocation of respective costs can be accurately determined); and

(c) The degree of competition in the service. For example, reflecting the different degrees of competition in the provision of Black Start as compared to the reserve/frequency control service markets.

Summary

81 The proposals set out in this document are designed to create alignment between the actions of the NETSO with each TO to support the innovative delivery of an economic, efficient and co-ordinated transmission service across GB which meets the long-term needs of customers and consumers and supports the development of our low-carbon energy future.

82 Constraint costs across the transmission networks are likely to be a particular area needing focus over the coming years as GB's transmission infrastructure is upgraded. Powerful, aligned incentives that reward the NETSO and the TOs for actions and innovations that minimise constraint costs will be particularly valuable for consumers in the RIIO-T1 period.

SO Incentive Principles

Overview

83 This section describes the principles against which we have developed our proposals for a package of SO incentive schemes to operate over the 8 year RIIO-T1 price control period. They draw on the principles set out in Ofgem's recent consultation 'System Operator Incentive Schemes from 2013: Principles and Policy' published in January 2012, together with the views expressed by ourselves and other stakeholders in response to that consultation.

84 In particular, our view is that incentive strength should reflect the operating environment that we work within, focusing on areas where we have more control and where it is beneficial that we have more discretion. These incentives need to adapt and evolve to ensure that they remain appropriate for industry's needs and the challenges in the period to 2021. The incentives should deliver a fair balance between risk and reward for consumers and National Grid.

Background

85 System Operator incentives have been in place for almost twenty years and have delivered significant benefits to stakeholders and consumers over this period. These incentives have created a focus around the outputs that are valued by customers; creating an environment in which we have developed innovative solutions, working closely with the two principle Scottish Transmission Owners (TO), to deliver ongoing improvements in the overall transmission service. The incentive schemes have evolved over time, increasingly dealing with forecasting uncertainty, whilst retaining focus on the outputs that customers value.

86 The principles of SO incentives are aligned to the RIIO philosophy (Revenue = Incentives + Innovation + Outputs) and we are committed to ensuring that the SO incentive arrangements integrate with the overall regulatory framework in which we operate.

87 As set out in the 'The System Operator role – now and in the future' section, National Grid's NETSO activity faces a challenging future, and will need to work in partnership with the TOs to develop and operate an economic, efficient and sustainable electricity transmission system. Against this changing future, it is more important than ever that strong incentives remain in place to ensure that we continue to deliver value to customers during this very uncertain and volatile period.

88 Stakeholders were largely comfortable with the concept that we as NETSO should be incentivised on the elements that we can reasonably control and/or forecast and that this approach reduced the scope for windfall losses and gains if the cost forecast models are right.

Over-arching Principles

89 The package of SO incentive schemes set out in these proposals have been designed against the following over-arching principles:

Delivering customer value

(a) The incentives should align our commercial interests with the interests of consumers; and

(b) Incentives should reflect our ability to deliver improvements to key outputs that are valued by customers.

Duration of incentive schemes

(a) We have developed an 8 year incentive framework which promotes alignment and co-operation between NETSO and TO activities to deliver the most optimal outcome for consumers in the longer-term;

(b) The duration for which scheme parameters are proposed within this framework depend on the confidence we and stakeholders have that the required outputs can be delivered at acceptable cost, given the predictability of costs and outputs and confidence in data and modelling. Shorter duration schemes are proposed for new arrangements to ensure they remain fit for purpose as they develop; and

(c) Given forecasting uncertainties and the need for transparency, it is proposed that each incentive should operate and report annually against associated targets. Methodologies/models are proposed for setting annual targets over the duration of the incentive schemes to deal with forecasting uncertainty.

Managing Uncertainty and Change

(a) We propose to limit windfall gains or losses through the use of target adjustment mechanisms to mitigate against market factors outside our control, with such mechanisms being reviewed periodically within the RIIO-T1 period; and

(b) Reopeners to deal with “game changers”, for example, Electricity Market Reform (EMR), Significant Code Reviews, and European Union driven reforms are proposed. We also propose to retain Income Adjusting Events to ensure appropriate funding can be provided for significant changes to costs which were not envisaged when allowed revenues under the incentive schemes were set. Further details on these elements can be found in the ‘Risk and Uncertainty’ section of this document

SO Exposure to Risk

(a) To the extent that we bear risks on behalf of consumers that we cannot fully control, we have proposed a risk premium within the package of incentives to finance this risk;

(b) We have sought to ensure we are able to earn a fair return in order to maintain the financial viability of the NETSO and provide adequate funding for the development of new capabilities; and

(c) We have sought to ensure that we are not exposed to unreasonable risk in circumstances that we are unable to control or reasonably forecast.

Incentivising Key Outputs

90 Incentives are sure to align NETSO actions with the interests of consumers where we have some degree of influence or control over a given output, and we can add value by improving the delivery of that output.

91 However, where incentives would expose the NETSO to factors it has little or no influence over, there is a risk of unwanted consequences including unjustifiable windfall gains or losses. We have sought to identify and avoid incentives that might encourage behaviours that would work against the best interests of customers and consumers.

92 Incentives on SO outputs can be either financial or reputational. Key outputs are generally subject to minimum statutory, licence or code obligations; they are subject to reporting requirements and often subject to infringement penalties if they are not delivered. The package of financial incentives set out in these proposals reinforce and sharpen these obligations to encourage the delivery of outputs beyond minimum requirements.

93 Key SO outputs valued by customers include:

(a) The efficient management of constraint costs;

(b) The efficient management of ancillary services costs;

(c) Energy balancing costs and transmission losses;

(d) Accurate demand and generation forecasts to support efficient market operation;

(e) Facilitating the timely connection of new generation connections and Grid Supply Points;

(f) Maintaining system reliability; and

(g) Operating a safe and sustainable system.

Duration of Incentive Schemes

94 The proposals set out in our submission are based on an 8 year incentive framework from April 2013 that aligns with the duration of the RIIO-T1 proposals. We support the move towards longer-term schemes. This creates stronger incentives to develop solutions and drive efficiencies that are in the long-term best interest of customers and consumers.

95 However, the electricity industry is entering a period of significant uncertainty and change as we move towards a low carbon economy during the next regulatory period. These external drivers will impact on the ability to forecast external SO costs and outputs with any degree of certainty beyond the next couple of years. Setting long-term ex ante targets against such uncertainty is not a robust basis for setting a long-term SO incentive scheme.

96 Variable scheme durations are therefore proposed within the 8 year framework where there are, for example, issues regarding the predictability of costs and outputs or confidence in data and modeling used to set targets. Shorter-term schemes are proposed for new incentives to ensure they remain fit for purpose as they develop.

97 Stakeholders have mixed views on the duration of the incentive schemes. The majority welcome the alignment of the SO incentives with the RIIO-TI regulatory framework but there are mixed views on whether the incentives themselves should be set over an eight year period. Stakeholders believed that long term schemes are beneficial; however lessons need to be learnt from the current 2 year scheme first before entering longer incentive schemes.

“We haven’t given enough time to learn from the current scheme arrangements”
Stakeholder Engagement Workshop, 23 February 2012

Annual incentives within an 8 year framework

98 We propose that each incentive scheme operates annually within this 8 year framework. Performance would be judged against an annual target, and aside from any residual reconciliation, incentive payments or penalties would form part of the BSUoS charges levied for that year. Furthermore, any applicable caps and collars, target adjustment mechanisms or Income Adjusting Events would operate discretely on an annual basis.

99 This is of importance to consumers, as it will determine when charges are adjusted to cater for incentive outcomes. We support the principle that charges faced by consumers should be cost-reflective, timely and appropriately targeted. For long term incentive schemes this means that charges should occur within the same period as the benefits to which they relate to avoid large adjustments at a later date that could affect the stability of customer charges.

Target Setting and Adjustment Mechanisms

100 Targets based on forecasts (ex ante targets) set against an uncertain future could easily lead to windfall gains or losses, and therefore a loss of focus in the incentive properties of the scheme. Incentives that could lead to windfall gains or losses may not drive the desired behaviors. This could reduce appetite to invest in an area to improve if potential windfalls overshadow any improvements that the investment is designed to deliver, as the profit (or reduced loss) from that investment may not be realised. This may lead to sub-optimal performance and therefore reduced value for customers.

101 In order to reduce the scope for windfall gains or losses, mechanisms can be used in the setting of targets on an annual basis. As for the current BSIS, a model and / or methodology was developed to calculate an annual target based on a defined set of inputs. Where external factors cannot be forecast and/or National Grid has limited or no control over them, these factors can be treated as ex-post inputs. This approach sharpens the incentive properties of the scheme by allowing greater focus on those factors we can influence or control (by eliminating those factors we cannot). This should assist with maintaining the incentive focus and reduce the scope for windfall gains or losses.

102 Ideally, these models/methodologies should be transparent in the way they operate and relatively simple to understand. Furthermore, it is important to develop a robust model/methodology at the outset, so far as this is possible, to minimise the requirement to re-open these models/methodologies on an ad-hoc basis.

103 However, any model/methodology that seeks to simulate the complex operating environment and networks that we operate over an uncertain 8 year period time horizon is likely to feature some degree of complexity and will unlikely be 100% accurate. In theory, the more complex the model, the more accurate it will be, but complex models/methodologies can become ‘black boxes’ requiring a significant overhead to manage. Our aim is to find the right balance between modeling complexity, accuracy, and ensuring that these are understood by our stakeholders.

104 Our experience to date of the current BSIS scheme has highlighted the importance of allowing experience from using the models to feed back into modeling improvements; thereby ensuring that models are current and reflect the environment in which we operate. This can be achieved by having a suitable process in place for refreshing the models and methodologies to cater for oversimplification, errors or other unforeseen modeling issues. Feedback from stakeholders has shown that they believe this is an essential part of a long-term scheme as it should also protect consumers from windfall gains by the NETSO. Stakeholders also noted the importance of creating a framework that focuses on the longer term but designed such that it remains current and live.

105 Using this approach to setting targets within a long-term framework is particularly important given the range of uncertainly we face in the operation of the NETS over the next 8 years.

Periodic review of target models/mechanisms/methodologies

106 The operation of the transmission network is a complex activity, and any model or methodology trying to replicate outputs from this activity is going to involve degrees of inaccuracy. Where there are concerns over the target mechanisms/methodologies and models used to capture long-term uncertainty, these can be reviewed periodically (hence the proposed concept of a 2+2+4 year BSIS scheme) within the 8 year incentive framework. Such reviews are particularly relevant during the early application of any given model / methodology.

‘given the length of the proposed incentive scheme period, we believe it would be appropriate to introduce a General Uncertainty Mechanism … on the understanding that it is only used to mitigate events which are unforeseen, have a low probability of occurring and have a significant impact on the SO.’
SSE response to Ofgem’s consultation on “System Operator incentive schemes from 2013”

Sharing Factors

107 Sharing factors are proposed for incentive schemes which are focused on minimising costs. Exposing the NETSO to a share of the external costs it manages creates an incentive to manage those costs efficiently. Sharing factors can range from 100% where the NETSO bears all the risk of managing costs and the consumer is charged a fixed price, to 0%, where the NETSO has an obligation to manage costs efficiently but has no direct financial incentive to do so.

108 External SO costs are far more volatile than internal SO costs and sharing factors have traditionally been relatively low to reflect the degree of control that we have over these external costs.

109 In creating alignment with TO incentives under RIIO-T1, we support the concept of consistent sharing factors to facilitate economic decisions where there are significant trade-offs between SO and TO costs and outputs. This is contingent on ensuring the incentive schemes are focused on elements we can control by minimizing the impact of those we cannot.

110 Inevitably, sharing factors of up to 50% to align with the RIIO-T1 proposals will introduce significant additional risk onto the NETSO activity. Nevertheless, the package of proposals (comprising target adjustment mechanisms, caps/collars, durations, IAEs, uncertainty mechanisms and risk financing) set out in this submission are designed to enable this alignment to occur.

The Use of Cap and Collars

111 While we are proposing that targets are set using adjustment mechanisms to take account of factors we cannot accurately forecast or control, there will inevitably be continued uncertainty around the accuracy of the models/ methodologies used to capture the complex reality of the networks we operate and the increasingly uncertain environment we operate within.

112 Targets could go significantly 'off track' over the duration of the scheme as a result of events outside our control. In order to protect both National Grid and customers from windfall gains or losses resulting from such events, caps/collars should continue to apply, but should be set at a level so as not to discourage economic trade-off in decisions between our NETSO and TO activities.

113 As we gain greater confidence in the models/methodologies used in setting annual targets, these caps/collars could be widened over time, possibly at the point that methodologies/models are reviewed and refined.

114 Stakeholders are in favor of caps and collars as they believe they protect them from any windfall gains or losses:

'the use of caps and floors also protect market participants and consumers from the SO achieving excessive gains and large swings in the incentive costs which are ultimately borne by consumers.'
SSE's response to Ofgem's consultation on "System Operator incentive schemes from 2013

115 Furthermore, reaching any cap or collar could be used as a trigger to reopen the scheme models/methodology, as these are a possible indication that the incentive scheme is not working as expected.

Framework Flexibility

116 As part of our package of proposals, it is appropriate to include provisions to allow individual schemes to be revisited in the event of changes to the commercial and regulatory framework in which we operate. Examples would include significant modifications to industry codes e.g. Significant Code Review (SCR), the introduction of EMR, changes resulting from UK & EU energy policy reforms and greater energy market integration across Europe.

117 Changes to the way the transmission network and the electricity market operate in the future may create opportunities to develop new incentive schemes. These might be on the back of new services or products that are developed by the NETSO, such as those being developed for EMR. The framework should be sufficiently flexible to allow new incentives to be created during the 8 year RIIO-T1 period where a clear customer benefit can be demonstrated.

118 This flexibility will also allow us to meet our stakeholders' expectations for an incentive scheme framework that focuses on the longer term but designed such that it remains current and live.

Income Adjusting Events

119 As part of our package of proposals, we propose the continued application of Income Adjusting Events (IAEs) at the current £2m threshold to allow safeguards for all parties, underpinned by a requirement to consult. The IAE provisions provide protection for both consumers and National Grid, allowing for funding adjustments to deal with significant and unexpected events that could not be foreseen at incentive framework conception. These provisions

allow for the incentive properties of the scheme to be maintained following such events.

120 We discuss this mechanism further in the 'Risk and Uncertainty' section.

Interaction with our SO submission under RIIO-T1

121 These proposals have been developed to align with our RIIO-T1 business plan submission in March 2012 for funding our internal SO costs. To the extent that this plan is designed to fund the delivery of the key obligations of our transmission business, the SO incentives proposed in this submission are designed to incentivise the delivery of key outputs valued by our customers over and above the baseline levels of performance expected of the NETSO. These incentives will encourage innovative strategies and drive collaboration with the TOs to provide an integrated, efficient and reliable transmission service to customers and consumers in the years ahead.

Financing Risk

122 The potential introduction of incentive schemes for up to 8 years with higher sharing factors and wider caps/collars will significantly increase the level of risk we face beyond current levels.

123 The NETSO activity does not have a sufficiently large balance sheet to underwrite the risks associated with the SO incentives. These risks would effectively be underwritten by the wider National Grid balance sheet and funded accordingly.

124 We also note the statement in Ofgem's January consultation:

"In particular, there should be no unnecessary risk around delivery of the SO outputs and the financial viability of the SO as an efficiently operating standalone entity should not be put at risk."

125 The funding risk associated with underwriting the NETSO activity could be factored into the allowed return on equity for the transmission business. However, we have requested funding to manage this risk via a risk premium within the incentive package for the NETSO activity, reflecting the additional risks arising from the SO incentives that the wider transmission business will need to underwrite.

SO/TO Interaction including links to the RIIO-T1 plan

Overview

126 The creation of long term value for the GB consumer ideally represents a cornerstone of all of the incentive schemes described throughout this document. An important building block in this will be the interaction between the NETSO and the different Transmission Owners (onshore TOs and offshore TOs (OFTOs)) within Great Britain. Alignment of incentives between the SO and TOs remains the best means of delivering the overall efficient outcome. A complicated interface, it is difficult and inefficient to fully contractualise or codify all of the TO interactions.

127 This section describes more closely these interactions and the management actions available to the System Operator.

Defining SO – TO interaction

128 In its January document[13,] Ofgem outlined the behaviours and decision making processes that are consistent with the high level Ofgem objectives identified earlier in this document. A key feature is the need to encourage the NETSO to identify and implement more effective ways of delivering efficient operational performance over the longer period that involves interactions with other parties, e.g. existing onshore TOs and the Offshore Transmission Owners (OFTOs).

129 In their responses to this consultation, stakeholders were supportive of greater SO and TO interaction. They said better alignment should bring benefits for consumers. They added that transparency of decisions taken between the SO and TO and the benefits for customers is key. This transparency was seen as important to ensure costs are not simply passed from one party to the other. One stakeholder added that greater interaction will become increasingly important when managing the connection of new generation sources as well as supporting the significant investment requirements identified through the RIIO-T1 process and outage planning.

Behavioural interactions

130 System access is an important consideration for the NETSO and TOs in delivering efficient system operation. The planned increases in construction, and subsequent maintenance activities, required in order to facilitate the connection of renewable generation sources however are likely to impact on the levels of system availability in both England and Wales, and Scotland.

131 Low levels of system availability can have a significant impact on constraint costs, restricting access to the network in delivering the overall cost

[13] System Operator incentive schemes from 2013: principles and policy

objectives. The deliverability of the outage plan is therefore a fundamental driver of efficiency in delivering construction and maintenance activities.

132 Alignment of incentives under common SO/TO ownership enables trade-offs to be made on a more straightforward and transparent basis, such that a range of issues can be considered in planning access to the system for works required including:

(a) The extent to which construction and maintenance activities can be bundled into an optimum number of outages;

(b) The ability to move outages given potential knock-on impacts to other works and outages within the plan;

(c) The costs and risks of the TOs associated with outage changes; and

(d) The expected costs and impacts of any constraints to the NETSO and consumers as a whole.

133 Furthermore, the complexity of these trade-offs is influenced by the number of outages that can be taken at any time in order to reduce the impact on the end consumer. This can mean that, as workload increases in constrained areas of the network, the planned schemes become increasingly interactive. This can also mean that the overall impact of outage changes can be difficult to quantify discretely for any one scheme.

Capital expenditure interactions

134 Similarly interactions with the capital plan of the TOs also occur. It is possible to reduce the cost of operation and/ or the environmental impact of asset operation by investing in additional or more efficient equipment. This has the effect of increasing network capability and potentially reducing maintenance requirements. The prioritisation of works within a particular capital scheme may help to reduce the impact on constraint management, whilst building in flexibility / redundancy to future proof against future operational issues.

The current approach

135 The roles of the System Operator and TOs are intrinsically linked such that the performance of the NETSO is highly dependent on the decisions made by relevant TOs in terms of the way it operates, develops and maintains its assets. In England and Wales, as integrated Transmission Owner (TO) and System Operation (SO) business, we have embedded processes to allow for holistic network decisions, thereby optimising the provision of network capacity to minimise the level of constraints. In the context of RIIO outputs and incentives, this integration means that we can specify and measure key outputs in terms of the full network service rather than a subset at the currently codified SO/TO interface.

136 For transmission activities outside of England and Wales, provisions under the electricity SO–TO (STC) Code seek to provide co-ordination between SO & TO, but without the appropriate financial incentives which can be applied directly by a TSO to drive efficiency and innovation maximising network availability and capacity.

Existing mechanisms for aligning incentives

137 Over the TPCR4 period we have played a key role in facilitating changes to the UK and European energy industries, including areas as:

(a) Implementing a ‘Connect and Manage’ regime allowing derogations from the planning standards to advance the connection of generation;

(b) Identifying and exploring the cost-benefit justification with industry for a programme of facilitating network reinforcements (Electricity Networks Strategy Group – ENSG);

(c) Exploring and proposing modifications to the security standards by means of the SQSS Review Panel consultations;

(d) Developing system operator processes for managing connection requests from offshore generators who will require new offshore transmission;

(e) Development and provision of process and information to allow for the connection of new offshore generators, and their subsequent co-ordination;

(f) Leading a consultation on future operational challenges for 2020 and beyond;

(g) Working in European regional initiative to progress the integration of electricity markets and make best use of interconnection; and

(h) Participating in European code development activities of the Electricity National Transmission System Operator – Electricity (ENTSO-E) forum and becoming an integral member of Co-ordination of European System Operators (CORESO).

138 These examples show how proposing and implementing commercial solutions to industry challenges is a key part of our NETSO role. Priority alignment and appropriate funding mechanisms will however be of particular importance going forward for both the NETSO and the TOs. Such alignment will become of increasing importance as further TOs are created, and the availability of these networks play an increasingly important role in the de-carbonisation of electricity supply.

Existing payments to TOs

139 Alignment of incentives between the SO and TOs remains the best means of delivering the overall efficient outcome. A complicated interface, it is difficult and inefficient to fully contractualise / codify all of the TO interactions.

140 Under the Transmission Licence[14], a mechanism is in place to enable the NETSO to pay the TOs for actual costs relating to changes to outages. This mechanism is not frequently used however for reasons which include:

(a) Limited timescales or available resource remaining to re-schedule outages; and

(b) Differences in incentive drivers. The TOs are incentivised to invest at lowest cost which may reduce opportunities for flexibility to be built into construction contracts (e.g. weekend working) to reduce constraint costs.

141 Currently however insufficient incentives are in place to encourage the TOs to offer options to maximise the availability of transmission capacity – e.g. enhanced ratings, rescheduling outages, live-line or accelerated working, etc, as they are cost neutral to the situation. The funds available to request TOs to re-arrange outages are unlikely to cover the TO's cost to re-optimise their outage programmes.

142 If anything, the opportunity to use this mechanism will be less frequent. The increasing levels of construction activity over the RIIO-T1 period will further restrict the ability to move outages as the schedule for system access becomes more constrained.

Consideration of Whole Life Value costs within our England and Wales franchise

143 A 'Whole Life Value' (WLV) Framework is in place within our England and Wales franchise in order to help balance the priorities of our SO and TO functions within investment decisions. Designed to consider a wide range of requirements for investments, the process aims to determine the most effective solution (not necessarily the cheapest in the short term). These take account of the shorter and longer term needs of the UK electricity and gas industries, including our stakeholders and customers, to create long term, optimised investments of enduring value.

144 Asset management decisions need to consider the whole asset life cycle from initial definition and design option selections through maintenance and operational flexibility and efficiency to final decommissioning and disposal. NETSO input is particularly valuable when considering versatility, operating expenditure, performance, system access and environmental impacts.

145 As a result, we have a number of investments in both our RIIO- T1 TO and SO price controls which respond to the challenges of increasingly dynamic and uncertain supply and demand backgrounds, including

(a) Network reinforcement works on key boundaries to reduce related constraints (for more detail, see our RIIO-T1 'Load-related detailed[15] plan' Annex);

[14] Special Condition AA5A: Services Activity Revenue Restriction. Part 2 (iv)

(b) Strategic Asset Management (SAM) and smart zone work to make the best use of assets we have; and

(c) Enhancing our system operation capability, for example improving forecasts of wind flows and enhancing on-line tools, so we can better optimise related reserve holdings and constraint actions.

146 In other TO territories however, the role of the NETSO in whole life asset management decisions is more limited, in part because the incentive to minimise constraint costs are not aligned.

Challenges for aligning incentives

147 The most significant uncertainty facing the NETSO during the RIIO-T1 period is the volume, location and type of generation to the transmission networks and the availability of the TO networks to enable system access for this generation. This problem is compounded with the 'Connect and Manage' access arrangements which have broken the contractual link between the connection of new generation and the completion of wider works. As a consequence, new generation projects with shorter lead times than those required for major transmission reinforcements will be connecting before the completion of wider transmission reinforcements.

148 This leads to a significant uncertainty regarding the need and timing of wider transmission reinforcements. In these circumstances, we need to balance the risks of investing too early in wider transmission reinforcements against the risk of investing too late, which would result in high constraint costs being incurred.

The need for alignment of the risk and reward framework

149 Whilst the roles of the NETSO and the TOs are intrinsically linked, the timescales within which the NETSO and TOs operate are different. This leads to important challenges in aligning incentives such that the risk/reward framework allows for effective trade-off of options and sufficient pay-back period.

150 To promote efficient NETSO and TO alignment, the parties providing these roles need to work together regardless of whether these roles are fulfilled within the same company or by different entities. It is important to make sure that network investment, operational solutions and system access in particular are co-ordinated between the NETSO and TOs in order to meet the needs of current and future customers in an efficient and economic manner. Specific measures to promote greater SO-TO alignment would need to be carefully considered to avoid any unintended consequences.

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[15] Our planned expenditure | Transmission: Electricity | National Grid

Approaches available to the NETSO

151 A robust means by which the SO can influence onshore and offshore TO investment in network capability has the potential to deliver efficiency in system operation. Such influence can drive value both through short term operational activities, as well as influencing investment over the longer term.

152 We have identified a number of approaches below allowing for the SO to influence TO decisions to ensure the delivery of end to end value for the consumer. The detail below is not exhaustive at this stage, and we will continue to seek opportunities to identify further mechanisms / areas that will allow for a greater degree of NETSO influence.

Short term Network Availability

153 We continue to develop, in conjunction with the TOs, the approach to Network Availability Policies (proposed as part of RIIO-T1). Such policies are expected to include;

(a) How we will prioritise and plan work on the transmission system, including decisions on network access, the placement, duration and flexibility of outages;

(b) Responding to requests to change the outage plans;

(c) Providing enhanced services over and above the baseline level of service in network availability provision such as Emergency Return to Service times, temporary bypass arrangements or two shift working;

(d) Managing risks relating to over-runs and delays to outages; and

(e) Assigning ratings for transmission network assets that affect the transfer ccapability of the transmission network.

154 A more coordinated approach with better communication between SO and TO will be vital to the delivery of a common network access approach and we continue to work towards this goal.

Influencing the development of investment

155 Analysis with respect to balancing investment against operational costs is to be taken forward through the production of a Network Development Policy statement, due to be implemented within the England and Wales footprint as part of the RIIO-T1 process. The statement will seek to balance the operational costs of wider transmission works to deliver additional boundary capacity, with the need case. Consideration against a range of demand and generation scenarios should allow for the identification of a number of TO investment solutions which can be considered as ‘least regrets’ for the consumer. We envisage that the NETSO will have a role in this process through the setting of scenarios for consideration and the evaluation of TO options.

156 The concept of the Network Development Policy Statement however is not a feature of other TO footprints, including the OFTOs. It may be that it is

appropriate to extend this process to other TOs, with the NETSO providing a co-ordination role and setting key inputs.

Aligning NETSO and TO incentives

157 Ofgem have as part of their January consultation document outlined their desire to see payments between the NETSO and TOs (including OFTOs) to incentivise behavioural changes, and/or change investment plans. We have previously sought to implement payment arrangements for outage movements or increasing capacity with limited success. Our proposals therefore centre on creating alignment between the SO and the TOs.

158 We have, in the 'Aligning NETSO and TO constraint incentives' section below, set out a commercial proposal to create stronger alignment between the NETSO and each TO to manage the cost of constraints on the relevant TO network. The incentive would see the transfer of a proportion of the incentive relating to the management of the volume of constraints to those parties best able to manage those risks, whilst maintaining the incentive on the NETSO to efficiently manage the cost of those constraints. This would place an equal incentive on all TOs to maximise the capacity made available on their networks, thus minimising constraint costs.

159 Creating this alignment will be critical if the consumer is to be protected from potentially huge congestion cost while the transmission infrastructure in GB is upgraded and expanded to create a sustainable energy market.

160 We believe that this alignment of incentives would be far more effective in ensuring the efficient management of constraint costs than the creation of complex contracting mechanisms between the NETSO and individual TOs.

161 In the short to medium term, it will be important to establish further commercial arrangements between the NETSO and the Scottish TOs. Over time however, we would envisage that these arrangements are also extended to Offshore Transmission Owners (OFTOs) and any other new transmission owners that may arise over the period.

Wider market changes to the regulatory framework

162 The process to agree an incentive framework for the NETSO comes at a time when substantial regulatory change is potentially underway. Recent consultations with respect to driving forward a co-ordinated offshore transmission solution[16], consideration of the wider role of the NETSO[17], onshore competition proposals and the implementation of legislation relating to the 3rd Energy Infrastructure Package all have the potential to change the nature of TO – SO interaction.

163 Over the next 8 years, greater onshore and offshore competition will lead to the creation of new TOs, thus increasing the number of NETSO interfaces and altering the sphere of influence required. TOs created under a competitive

[16] Offshore Transmission: Consultation on Potential Measures to Support Efficient Network Coordination March 2012
[17] Integrated Transmission Network Planning consultation March 2012

process may operate according to different drivers than the current incumbent onshore TOs. A need to deliver capacity to customer needs coupled with a more limited portfolio allowing for less flexibility is likely to limit the degree to which the NETSO is able to influence the plans of the TOs.

164 As wider market frameworks development, the question of incentive alignment will need to remain at the forefront of any decision making if the right operational and investment decisions are to be made.

Balancing Services Incentive Scheme (BSIS): Introduction

Overview

165 The following sections of this plan set out our proposals for the Balancing Services Incentive Scheme (BSIS) to be implemented from April 2013, for the RIIO-T1 period. More specifically, these sections provide our proposals for:

(a) BSIS scheme design;

(b) The review and amendment of the ex ante or ex post treatment of inputs;

(c) Energy cost target modelling;

(d) Constraint cost target modelling;

(e) Aligning NETSO and TO constraints incentives;

(f) Annual model review;

(g) Black Start; and

(h) Transmission Losses.

166 We set out an 8 year BSIS framework which seeks to maintain and focus the incentive on us to reduce costs and increase value to the end consumer in those areas that we can control and influence. This framework comprises three phases of 2, 2 and 4 year durations with differing scheme parameters applicable to each phase. The framework is underpinned by improved cost target models from those implemented for the 2011-13 BSIS (current scheme) following a newly adopted approach to incentivisation in April 2011.

167 Stakeholders have expressed the views that, as the current incentive is relatively new, regular reviews are important to detect any ongoing modelling or scheme design issues.

“It would be more appropriate to continue with this scheme for a while to ensure it works appropriately before planning any further significant changes.”
EON’s response to Ofgem’s consultation, on ‘System Operator incentive schemes from 2013’

168 The models themselves are structurally based on the current scheme models but have been enhanced such that they are more robust and accurate for an 8 year framework whilst also minimising the scope for windfall gains and losses. Most importantly, the models and supporting review processes ensure sufficient flexibility so that they can be adapted to the challenges in system operation that lie ahead.

169 The transmission losses and black start components of BSIS have been reviewed and further developed such that incentives for these elements better align with the principles behind the constraints and energy components. More

specifically, our ability to control and/ or forecast these two cost categories has been more appropriately reflected throughout these proposals.

170 In consideration of the move to a longer term incentive framework than experienced to date, we have sought to assess and manage the risk associated with a longer timeframe. These have either been mitigated through design of processes by which models, methodologies and scheme parameters can be periodically reviewed or through specific re-openers/ uncertainty mechanisms. These are set out throughout these sections and more specifically captured in the 'Risk and Uncertainty' section towards the end of our plan.

Background

171 BSIS is designed to deliver financial benefits to the industry and consumers via reductions in the costs or minimising risk associated with operating the NETS. BSIS has been in place since the implementation of the New Electricity Trading Arrangements (NETA) in 2001 and, prior to April 2011, covered 1 year periods where a target was set and agreed with Ofgem prior to the start of each year[18].

172 In April 2010, following implementation of the 2010/11 BSIS, Ofgem initiated a SO Incentive Review (SO Review) to determine whether the models and modelling approach we used were suitable for application to multi-year incentive schemes (from 1 to 2 years in the first instance). It was proposed that we develop a BSIS methodology which incentivises the NETSO on the costs and cost drivers that are within our control. To achieve this approach, Ofgem concluded that a number of variables which form inputs to BSIS cost forecast models should be input to those models ex post (using outturn data) as opposed to ex ante as they are external factors beyond our control and/or ability to forecast. An example of such an ex post input would be power price which can be highly volatile and is not something that we can control.

173 We adopted this new approach to incentivisation which led to procurement of a new model for constraints (Constraint model) and in-house development of the energy models such that both ex ante and ex post inputs could be accommodated. We also set out a methodology[19] by which inputs to the cost target models could be assessed to determine whether they should be treated as ex ante or ex post in the models.

174 This revised approach to incentivisation therefore does not feature the agreement of a forecast of Incentivised Balancing Costs (IBC) prior to the start of the scheme. Instead it requires agreement between National Grid and Ofgem on models and model input data so that modelled 'target costs' can be calculated on a routine basis throughout the scheme. Ultimately this method for determining a rolling IBC target facilitated the implementation of a longer two year scheme duration, commencing 1 April 2011.

[18] This is with the exception of 2006/7 where no incentive scheme was agreed with the Regulator.
[19] The current Statement of the Ex Ante or Ex Post Treatment of Modelling Inputs Methodology can be found at: http://www.nationalgrid.com/NR/rdonlyres/AF9269A3-F5CA-4153-897B-4EB0B74ADE4B/47902/Treatment_of_Modelling_Inputs_Methodology_Issue1_18July2011.pdf

175 Ofgem proposed in its January 2011 consultation that the newly adopted BSIS methodology be employed for the scheme during the RIIO-T1 period. Ofgem do, however, recognise that the models underpinning this methodology are in their infancy and that further improvements may be identified both prior to, and during, the RIIO-T1 period. We have sought to take this into account when setting out our proposals for BSIS.

176 The current and proposed scheme is a bundled scheme for which a target cost is determined using a number of models and methodologies[20]. At a high level the scheme encompasses the following sub-cost components which, for simplicity, have each been assigned a discreet section of our plan:

(a) Energy – these costs include Energy Imbalance, Margin, Fast Reserve, Frequency Response, Footroom and Reactive Power. These cost targets are modelled principally using regression analysis and are described in more detail in the 'Energy Modelling' section below;

(b) Constraints – the costs associated with managing bottlenecks in the system such that flows can be optimised on the NETS. A constraints cost target is modelled using our new Constraint model which generates an unconstrained and constrained generator running schedule to determine a cost target. This will be described in more detail in the 'Constraints Modelling' section below;

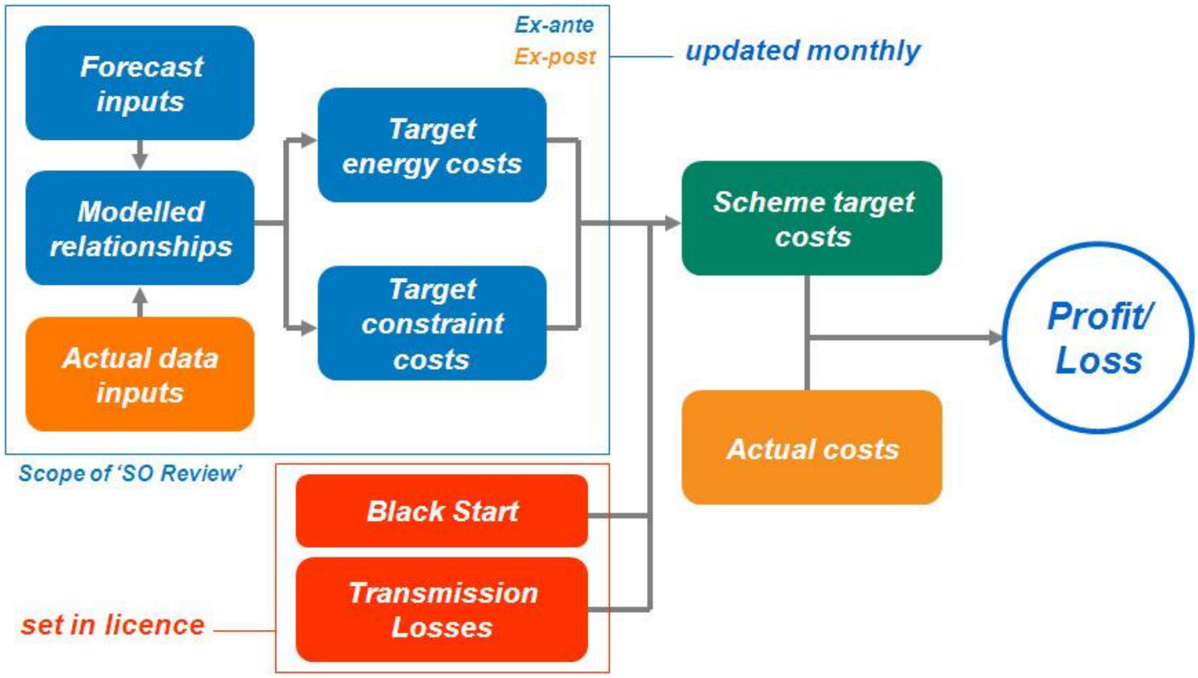
(c) Black Start – the costs incurred to maintain service capability to recover the NETS in the event of a partial or total system shutdown. Further details of the proposed incentive for this element are set out in the 'Black Start' section below; and

(d) Transmission Losses – the incentive cost associated with power losses resulting from the NETS. Further details of the proposed incentive for this element are set out in the 'Transmission Losses' section below.

177 The diagram below demonstrates how the components of BSIS come together to determine an overall scheme target. It also shows (in the top left-hand box) how ex ante and ex post (actual data) inputs are brought together using relationships defined within the models themselves:

[20] The current scheme is supported by three modelling methodologies which can be found on our website at: http://www.nationalgrid.com/uk/Electricity/soincentives/docs/.

The Components of BSIS



Developments during the RIIO-T1 Period

178 As set out in the 'SO Role: Now and into the future' section above, we anticipate significant change in the operating environment over the course of the RIIO-T1 period. The anticipated growth in intermittent generation, particularly when connecting prior to completion of wider transmission reinforcements under the connect and manage regime, will increase constraint volumes and our operating reserve requirement. Constraint costs in particular are forecast to be the biggest cost category within BSIS; hence we set out below how we have focussed our efforts to ensure that the model that derives a constraint incentive target is as accurate as possible and reduces the likelihood of windfall gains and losses to the end consumer.

179 Whilst the RIIO-T1 period presents challenges in terms of changes to our operating environment, there will also be new opportunities to create value on behalf of consumers. These opportunities will be sought, for instance, via development or creation of balancing services alongside new technologies delivered to provide such services. It will therefore be critical for us to engage with our stakeholders and provide the industry with effective information to facilitate these markets. Innovation will be key to breaking new ground and meeting new challenges. We set out how innovation has played an important role in the past, and will continue to do so in the future, in the 'SO Innovation' section of this plan.

Energy and Constraint Cost Modelling

180 The proposed Energy and Constraint models, that will determine incentivised cost targets for these elements of the BSIS throughout the RIIO-T1 period, are described in more detail in their respective sections below.

181 Following the implementation of the current scheme on 1 April 2011, Ofgem requested that further work be undertaken to the models via a Supplementary Review[21]. We agreed to investigate various areas for future improvements in modelling to facilitate the continued development of longer term schemes. These areas for development were set out in a Scheme of Work and agreed with Ofgem. We have therefore committed considerable analytical resource to further develop and extend the models, in line with the Scheme of Work, such that they are more suited for an 8 year framework.

182 During the previous 14 months, operational experience has also been gained with the current scheme methodologies in order to determine areas that are working as intended and those that require further refinement. The combined activities of future scheme modelling research and current operational experience has fed into the proposals set out in the following sections to deliver proposals that are appropriate for longer term incentives.

183 Our proposal is to employ the current scheme methodology and models (i.e. the energy and constraints models), with refinements made to models and some of the data inputs. From current scheme experience we have been able to determine which of the model inputs we can forecast and control. We have undertaken a review of the treatment of all inputs on this basis such that model accuracy is improved over a longer incentive framework whilst still focussing the incentive on us to reduce costs in areas we can influence. This review and reassessment of model inputs is set out in the 'Ex ante or Ex post Treatment of inputs' section.

184 Therefore we have sought to further enhance current methodologies and models to better meet the overarching incentive principle that we should be incentivised to reduce costs that are within our control thereby further reducing scope for wind fall gains or losses. We also seek to share risk appropriately between us and end consumers ensuring that any risk sits with the party best placed to manage it. In order to practically implement a methodology and models for an 8 year framework, we have been careful to ensure that these are as understandable, transparent and auditable as possible.

185 The modelling challenge associated with the constraints model, discussed in the 'Constraints Modelling' section, is focussed more around the detail of the modelling methodology rather than the modelled relationships. Conversely development of the energy model is associated with both the detail of the modelling methodology and the modelling relationships. The current energy model has performed well over the current scheme duration; however there are clear drivers that will impact modelled relationships in the future.

186 Work has been undertaken to understand the dynamics of the modelled relationships such that they can be developed further. This approach has resulted in less detailed proposed changes to the energy model at this time although work will continue in this area over the coming months such that a robust model and methodology is in place for the RIIO-T1 period.

[21] Further model work is set out in Licence Condition AA5I - Requirement to conduct a Supplementary Review to develop and undertake a Scheme of Work to facilitate continuing development of a longer term balancing services activity restriction on external costs

Modelling Principles

187 As set out above, we are strongly supportive of the principle underpinning the current and proposed schemes where the incentive is focussed on areas that we can control and influence. In addition, through our discussions with Ofgem over the previous few months, we have determined some high level modelling principles against which to assess any model enhancements that we make prior to the RIIO-T1 period. Thus any model development should:

(a) Provide an incentive on the NETSO together with TOs to optimise and reduce costs to the end consumer;

(b) Avoid perverse incentives e.g. a model development which removes the incentive for us to contract for a service ahead of real time rather than leaving it to be managed in the BM;

(c) Be better for consumers than an ex post monitoring or the current model i.e. the development maintains the incentive on us to reduce costs;

(d) Be understandable, where key processes, inputs and outputs are easy to explain to our stakeholders;

(e) Enable a holistic modelling of the system e.g. the new Constraint model is used to determine a constraint cost target for the whole of GB;

(f) Demonstrate that the NETSO is adding value to end consumers; and

(g) Enable the model to be more robust and accurate over a longer incentive period in terms of determining an incentive cost target.

188 If the above principles are met, scope for windfall gains or losses to the end consumer should be minimised and the incentive further focussed on those elements that we can control and influence. The modelling methodology should therefore enable reflection of the decisions and actions that we take to reduce costs. For example, striking economic and efficient contracts for reserve, response and constraints above an agreed baseline should be reflected in actual IBC being lower that the target set by the models. This provides the correct strength of incentive on us to deliver the lowest possible costs for managing the NETS and hence the lowest possible costs for consumers.

189 Across the proposed 8 year incentive scheme period, there will be considerable change as described in the 'The System Operator Role: Now and into the future' section. Designing a scheme methodology that can be sufficiently flexible to cater for all foreseeable, let alone unforeseeable, changes is particularly challenging. We have therefore incorporated transparent and auditable mechanisms whereby modelling amendments can be made on a periodic basis which seek to ensure that the models remain current and robust throughout the scheme.

190 These changes may include software updates, input clarifications and optimiser enhancements, and can ultimately have an impact on the accuracy of the output of the models. We describe what this process will entail and the types of changes we might seek to make in the modelling sections below. This type of modelling adjuster mechanism acts as a constant check that the models are performing as they should and that we are incentivised to reduce the costs that we can control as NETSO.

Risk and Uncertainty

191 Aside from the aforementioned modelling 'health check' process, there may be events that occur during the RIIO-T1 period so significant that they require a fundamental review of the proposed incentive scheme. Examples of this could include Electricity Market Reform (EMR) and implementation of the European Network Codes. EMR in particular is likely to have a significant impact on the type and cost of services that we procure to the extent that models and the relationships between historic variables may no longer be valid. It is therefore envisaged that specific reopeners or uncertainty mechanisms be put in place to cater for such uncertainty.

192 The potential impacts of likely future industry developments, and any anticipated consequences in terms of incentive scheme design, are explored further in the 'Risk and Uncertainty' section later in this plan.

BSIS: Scheme Design

Overview

193 This section presents our proposals for the structure of the 8 year BSIS incentive framework to apply from 1st April 2013 given the principles set out in the earlier 'SO Incentives Principles' section. This structure has been designed to deliver long term value to consumers whilst maintaining a fair balance of risk and reward between us and consumers.

194 We propose a framework for BSIS which comprises three phases within the 8 year framework, with scheme parameters applied annually across each phase. In order to mitigate the risk of windfall gains or losses, we propose to gradually increase the levels of caps/ collars and sharing factors from those applied to the current scheme as the period progresses thus creating ultimate alignment to RIIO-T1 TO parameters by the second half of the incentive period. This reflects our expectation that BSIS models and methodology will evolve through the duration of the scheme, giving greater confidence in the ability to set an efficient benchmark for target costs as the scheme progresses.

Scheme Structure

High-level scheme structure and length

195 We agree with the merits and support implementation of an 8 year incentive framework, whilst ensuring that incentive focus is maintained, and windfall gains and losses are reduced where possible over that period. A longer term incentive framework for the BSIS should encourage National Grid to pursue efficiencies that either take longer to develop, for example changes to industry Codes, or pay back over a longer period than would be possible with much shorter term schemes e.g. asset based solutions.

196 We strongly believe that longer term schemes should be implemented in such a way as to protect consumers and the NETSO from windfall gains and losses and present a fair balance of risk and reward. In order to achieve this and maintain incentive strength on the NETSO to reduce costs, it is essential that careful consideration is given to the weighting between incentive duration, sharing factors, caps/collars and the range of uncertainty mechanisms available.

Scheme parameters

197 Given the proposed approach to modelling the BSIS incentive target (i.e. the derivation of annual targets with an annual review of the modelling methodology); we propose that BSIS parameters are also set and applied annually. These annual parameters will be applied to outturn Balancing Costs for the relevant year to determine the incentive profit or loss for that year. This approach does not undermine the objectives of, and drivers for, a longer term incentive scheme as the same methodology will underpin the whole framework, thereby ensuring that actions taken in the shorter term can still

derive value in the latter years. It also means that customer charges should continue to be adjusted to include incentive profits and losses within each financial year thus minimising the need to make large charge adjustments at the end of the multi-year framework.

Scheme length

198 Ofgem propose in its January consultation that the BSIS length should be increased from the current two year scheme to a 4+4[22] year scheme using the new methodology implemented for the current scheme (2011-13). Ofgem, however, do recognise that the models underpinning this methodology are in their infancy and that further improvements may be identified over time.

199 We agree that whilst BSIS is by no means a new scheme concept for the RIIO-T1 period, the models and methodologies used to derive the cost target require further development to achieve the required robustness and accuracy to support longer term schemes. In the sections above, we have sought to identify areas of weakness within the current methodology and models in order to improve modelling accuracy and further reduce the possibility of windfall gains or losses. However the veracity of those improvements will remain to be experienced in earnest.

200 Thus to transition to a 4 year incentive duration from the current two year scheme, given its current status, would present significant risk of windfall gains and losses, both for us and consumers. We therefore propose that the 8 year framework for BSIS be split into three phases of 2+2+4 year long schemes where the methodology and models may be reviewed between each phase.

201 This structure aligns with Ofgem's view in its January consultation that 8 year incentive schemes could be designed to mitigate risks associated with modelling and data uncertainty in the early years. It also allows for varying scheme parameters to be applied during the different scheme phases as confidence in modelling accuracy and data grows. We believe that the amendments proposed to improve the models and mechanisms set out for 'health-checking' those models on a periodic basis will increase confidence over time.

202 This type of approach was supported by some of our stakeholders who expressed concern that we had only recently transitioned to a two year scheme and that a four year scheme presents even more uncertainty and risk to the industry where questions on modelling accuracy have yet to be answered.

"Is there scope to extend the current scheme to continue to learn more from it?"
"We haven't given enough time to learn from the current scheme arrangements"
Electricity SO Incentives Stakeholder Workshop, 23 February 2012

[22] This means that whilst the over-arching methodology is set for 8 years, an examination of the underlying models and data used takes place at a mid point after 4 years.

203 Therefore the scheme parameters set out below have been designed to reflect an anticipated growth in confidence in the models and reduction in risk with improved modelling accuracy, whereby caps/ collars and sharing factors become wider/ higher throughout the 8 year period. Ultimately, during the second half of the scheme period, these parameters become aligned with RIIO-T1. The parameters set out in this section represent our current view of the forthcoming 8 year period but it is proposed that these may also be reviewed at each scheme review point to take into account evolution in the operating environment.

The target and potential need for a dead-band

204 As for the current 2011-13 BSIS, there will be no ex-ante agreed forecast of Incentivised Balancing Costs for the duration of the RIIO-T1 incentive framework. Instead, a monthly target will be calculated on an ex post basis using both the agreed ex ante and ex post data in conjunction with the models to derive a total modelled 'target' cost for each year. Our incentive performance will be determined by comparing actual costs with this target.

205 Prior to the current scheme, dead-bands existed as a mechanism to manage the uncertainty associated with an agreed ex ante forecast of incentivised costs. The introduction of the new approach to incentivisation for 2011-13 as described above meant that a smaller dead-band of ±£5m could be adopted since the level of uncontrollable risk had been reduced with the use of ex post inputs adjusting the target.

206 The current dead-band of +/- £5m was, however, proposed as a means to reducing risk of a different kind, namely the risk associated with the new set of models (Constraint and Energy models) to support the new approach to incentivisation. Given the relative size of this dead-band compared with the overall cost of BSIS each year it is proposed that the concept of a dead-band ceases to form part of the scheme design commencing April 2013.

Caps and collars

207 The current BSIS cap / collar sits at +/- £25m per annum (+/- £50m for the two year scheme), an increase from around +/- £15m to those schemes prior to 2011. The ex ante / ex post approach to deriving a modelled BSIS cost target should mean that our profit or loss position is more stable and more directly linked to the actions we take to deliver value. Hence, in theory, a high profit cap / low loss collar could be set to act as a greater incentive on us to innovate and deliver value in exchange for a greater level of reward.
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208 In its January 2012 consultation Ofgem considered that it should be possible to widen, or even remove, caps and collars for the BSIS under the RIIO-T1 period, with narrow caps and collars undermining the incentive properties of the framework. However, we consider that, in reality, it is still necessary to limit the maximum exposure that we have under the scheme; and from the industry / regulator's perspective to limit the maximum reward. This is particularly pertinent given experience to date of the current scheme where windfall gains and losses have materialised despite implementation of a methodology which seeks to reduce them.

209 Our stakeholders have mixed views on the adoption of wider or no caps / collars for a future scheme. Whilst some thought that wider caps / collars should be adopted to drive the appropriate level of effort to reduce costs and create efficiencies, others thought that unlimited caps/ collars would introduce too much unpredictability requiring much shorter scheme durations.

210 The setting of profit caps (and loss collars) at a wider value than currently in existence has the potential (in conjunction with other factors) to place greater incentives on the NETSO to deliver efficiency in system operation. At the same time however, we are mindful of the continued uncertainty surrounding the operation of a still relatively new ex ante / ex post methodology and models which increase the windfall risk presented by wider cap and collar parameters.

211 Our current view therefore is that, for a scheme with a symmetrical profit cap / loss collar and modelling which is yet to be proved sufficiently robust, it is appropriate to adopt a transitional approach to widening caps/ collars from the current level of £25m per annum. This serves to minimise windfall risk until the operation of the models are better understood and refined such that windfall gains and losses are reduced as far as possible. At the same time, the strength of incentive is gradually increased as a higher profit opportunity (or loss potential) is available.

212 We consider it appropriate to increase the cap/ collar from £25m per annum presently to £30m per annum for the first 2 year phase of the incentive framework, subsequently increasing to £40m per annum for the second 2 year phase. Following an anticipated growth in confidence of the modelling methodology over the period we propose that caps/ collars are further widened to £50m per annum in the final phase of the scheme which equates to the second half of the RIIO-T1 period. A summary of the overall scheme profile and associated parameters is set out in a table at the end of this section below.

213 These proposed caps/ collars are of sufficient magnitude to represent a meaningful incentive for delivery of value to the end consumer (or to hedge against potential risks) over and above that which would be expected from simply meeting the 'efficient and economic' obligations of our licence.

Sharing factors

214 Sharing factors determine our share of the profit or loss we deliver when our actual costs are compared to the incentivised cost target. Low sharing factors mean that we face limited exposure to savings made or costs incurred through our actions; hence the incentive to deliver value could be considered weaker and the scope for reward may not be commensurate with the cost of delivering change.

215 Conversely, high sharing factors mean that we face significant exposure to savings made or costs incurred through its actions; hence the incentive to deliver value could be said to be stronger and the scope for reward may be such as to encourage significant value creation. The newly adopted approach to incentivisation for the current scheme aimed to minimise our exposure to factors beyond our control, hence the sharing factor was increased from previously seen levels to 25%.

216 In its January 2012 consultation, Ofgem considered it appropriate to increase sharing factors yet higher from the current scheme level to 50% in order to continue to provide the NETSO with a strong incentive to reduce external balancing costs. This would also align with the RIIO-T1 sharing factor thereby creating greater alignment between NETSO and TO incentives, encouraging efficient delivery across SO and TO particularly with regard to managing constraint costs. Some of our stakeholders also felt that incentives should ideally be symmetric between SO and the three TOs to encourage collaborative working and reduction of constraint costs.

217 The recently adopted approach to incentivisation, in seeking to remove volatility, should reduce the need for lower sharing factors to manage windfall risk. Furthermore, under the current approach, where we see potential risks, a higher sharing factor would increase the incentive to 'hedge' them (even if cost of hedging removed any profit / increased any loss). This type of risk avoidance would also protect consumers, and the effect would be amplified by a higher profit cap/loss collar as proposed above.

218 We agree that, for the RIIO-T1 period, we should ultimately look to share our exposure to profit and loss under the scheme equitably with consumers i.e. sharing factors should ultimately equal +/- 50%. However, as set out in the length of scheme and caps/ collars sections above, we consider that to increase the sharing factor to 50% from the current level of 25%, given the infancy of the models and methodology, would present too much risk to both us and consumers. As we allow time for the models to embed, and use the mechanisms that we have proposed to refresh and evolve the models, the windfall risk should be further reduced. This will also allow for sharing factors to be increased throughout the period, to complement the cap / collar increases described above.

219 We therefore consider it appropriate to increase the cap/ collar from 25% per annum presently to 30% per annum for the first 2 year phase of the incentive framework, subsequently increasing to 40% per annum for the second 2 year phase. Following an anticipated growth in confidence of the modelling methodology over the period we propose that caps/ collars are further widened to 50% per annum in the final phase of the scheme which equates to the second half of the RIIO-T1 period. This means that alignment to the RIIO-T1 sharing factor is achieved for the latter half of the incentive framework.

Proposed scheme profile

220 The table below summarises our proposed scheme structure and associated parameters for the RIIO-T1 period as described above. The parameters for each scheme phase should be subject to final agreement at the preceding review point.

Proposed scheme structure and parameters

Scheme Phase	Phase Dates	Number of Years	Annual Cap/ Collar	Annual Sharing Factor
1	Apr ‘13 – Mar ‘15	2	± £30m	30%
2	Apr ‘15 – Mar ‘17	2	± £40m	40%
3	Apr ‘17 – Mar ‘21	4	± £50m	50%

221 As the above table shows, although the annual cap/ collar and sharing factors increase, the overall incentivised range is maintained at +/- £100m per annum which is comparable to the current scheme. Therefore it is our exposure to that range that increases over the period which corresponds to an increase in modelling confidence and refinement to the proposed methodology. As modelling is deemed more accurate, scope for windfall gains and losses to both us and consumers is further reduced and the incentive more focussed on those elements that we can control. This should result in an overall incentive to go ‘above and beyond’ in the quest for efficiencies whilst also recognising the level of risk associated with those activities for which adequate reward is received.

Mid Scheme Reviews

222 Due to the three phased approach as set out above, there will be two opportunities to review the scheme parameters and methodologies within the incentive framework such that they continue to present a fair balance of risk and reward between us and consumers. These review points will therefore be used as an opportunity to consult with the industry to review any fundamental changes required to the schemes that are not captured by the annual model review process as set out in the ‘Annual Model Review’ section.

223 We will therefore seek to publish an industry consultation in the final quarter of the last incentive year of each scheme phase. Any amendments required to the scheme and/or supporting methodologies will be applied for the following scheme phase. Such amendments may include:

(a) Review of scheme parameters from those set out above – for example this might be as a result of a re-opener being applied in the previous scheme phase which significantly increases (or reduces) the risk associated with increasing caps/ collars and sharing factors;

(b) Fundamental modelling amendments which are not captured by the annual review process – for example this may include addition or removal of explanatory variables that derive regression coefficients; and

(c) Review of scheme methodologies – for example the frequency with which inputs are input to the model, the addition of new inputs to the models and reassessment of the constraints ‘uplift factor’ proposed in the ‘Constraints Modelling’ section below.

BSIS: Ex ante or Ex post Treatment of Inputs

Overview

224 Following introduction of The Statement of the Ex Ante or Ex Post Treatment of Modelling Inputs Methodology[23] ('ex ante/ex post methodology') for the 2011-13 BSIS, this section sets out our proposed developments to that methodology to apply to incentives from April 2013. Such developments include evaluation of the assessment criteria employed to determine whether modelling inputs should be treated on an ex ante or ex post basis in the context of longer term incentives; and reassessment of the inputs themselves. The rationale for any changes to the methodology are also set out in this section, which is underpinned by the incentive principles set out earlier in this document, the consideration of longer term schemes and experience from the current BSIS.

225 In our stakeholder workshop in February 2012, stakeholders were largely comfortable with the concept that as SO we should be incentivised on elements that we can reasonably control and/or forecast and that this approach reduced the scope for windfall losses or gains if the cost models are right.

Background

226 The ex ante/ ex post methodology is one of a suite of three methodologies that we employ to calculate the modelled target costs for the current BSIS, against which actual balancing costs are compared, on a month-by-month basis. These three documents were published at the start of the current scheme in accordance with Schedule A of Special Condition AA5A of our Transmission Licence and were developed as part of the SO Review in 2010.

227 The exercise to determine which inputs to the models should be treated as ex ante and which ex post included the identification of BSIS cost drivers and development of criteria. This allowed for assessment of the extent to which inputs could be controlled and/ or forecast over the period in question. For those inputs where the SO was assessed to have no or low ability to control and/ or forecast the driver(s), the input would be treated as ex post. Conversely, for those inputs where the SO was assessed to have medium or high ability to control and/ or forecast the driver(s), the input would be treated as ex ante.

228 Ofgem set out in their SO Incentives Principles from 2013 consultation in January 2012 that it believed the current methodology to be suitable for incentive schemes under RIIO-T1. However, it recognised that refinement would be required to all the methodologies particularly given that they were still in their infancy.

[23] The current methodology statement can be found on our website at: http://www.nationalgrid.com/NR/rdonlyres/AF9269A3-F5CA-4153-897B-4EB0B74ADE4B/47902/Treatment_of_Modelling_Inputs_Methodology_Issue1_18July2011.pdf

229 Therefore in light of experience gained under the current scheme for a 14 month period (April 2011-May 2012), and the prospect of a longer term 8 year incentive framework, we have undertaken a review of the methodology. We believe that this review will facilitate the development of longer term incentive schemes and further reduce the possibility of windfall gains or losses to the consumer by, for example, increasing modelling accuracy.

230 The relative treatment of modelling inputs is discussed below with commentary primarily focusing on those inputs which are to be treated differently to the current scheme. However, before reassessment of the drivers, we firstly evaluate the definitions of ex ante and ex post inputs and the assessment criteria employed to determine this treatment.

Categorisation of Inputs

231 The extent to which the drivers of system operation costs can be controlled or forecast to enable effective incentivisation as part of a system operator incentive scheme is fundamental to whether they should be considered as ex ante or ex post inputs to the incentive models. It becomes particularly important that this categorisation is as accurate as possible for an 8 year framework where the operating environment is anticipated to change so considerably. Ex ante and ex post inputs are described currently within the ex ante/ ex post methodology as follows:

(a) **Ex-ante inputs** will be set prior to the commencement of the scheme. The same dataset for these inputs will be used whenever the models are run throughout the 24 month duration of the scheme and would not normally be updated as the scheme progresses (except under specific agreed circumstances via an Income Adjusting Event); and

(b) **Ex-post inputs** will be collated on a monthly basis following the commencement of the scheme and combined with the ex ante dataset, to be run through the models to determine the target level of costs that we should be incentivised against.

232 It is proposed that the above definition of ex ante inputs is amended in the methodology to reflect that, under even longer term schemes, ex ante inputs themselves may not remain constant throughout the scheme duration. Instead, the source of ex ante data or the way in which the ex ante dataset is to be derived will be defined and remain constant, but the dataset itself will be updated periodically and input to the model at pre-determined intervals.

233 This is to ensure that ex ante inputs, and therefore the resulting model output, continue to reflect an appropriate balance between incentivisation and removal of risk over the incentive period. These updates will allow the ex-ante data to continue to reflect as closely and accurately as possible the system conditions faced when operating the system, such that any action that we take to reduce costs is not adversely affected by any modelling inaccuracy.

234 It is not proposed that the above definition of ex post inputs is changed from the current methodology. These will continue to be input monthly to the models in combination with any ex ante datasets to determine the target level of costs.

Criteria to assess the treatment of modelled parameters

235 In order to investigate the extent to which we can be appropriately incentivised, the ex ante/ ex post methodology considers our ability to forecast or control cost drivers, with particular reference to the potential mechanisms we can use to influence them. Similarly we would expect to use the same approach for any new cost drivers that arise over the RIIO-T1 period.

National Grid's ability to forecast inputs to the energy and constraint models

236 Our ability to forecast inputs, even up to lead times of 12 months, is dependent on a number of factors. Currently within the ex ante / ex post methodology, our ability to forecast each input is considered against the following measures:

Generic assessment criteria for National Grid's ability to forecast inputs

Measure	Detail
Availability of data	Inputs may be based on submitted data (which is likely to have a range of certainty associated with it) or on collected data from other sources (including outturn data). It is assumed that data is already available to us – where additional data is required, the potential cost of procuring such data is not explicitly considered.
Volatility of drivers	Inputs may be based on plant parameters, and hence be reasonably stable, or they may be based on economic fundamentals/market behaviour (such as fuel prices), with the potential to exhibit significant volatility. Assessment of volatility is assumed to apply for 24 months unless otherwise stated.
Applicability of historic data trend analysis	Inputs may be driven by known behaviours studied over a period of time, such as demand forecasts, and hence be forecast with a good degree of certainty. Alternatively, they may be driven or influenced by one-off/exceptional events, such as significant prolonged plant failure, which might not normally be considered as part of a 'reasonable' forecast.

237 The extent to which each measure contributes to our ability to forecast an input is assessed to give an overall forecast confidence within the methodology, as follows:

(a) **None:** We have no ability to forecast the input;

(b) **Low:** Our ability to forecast the input is limited, for example due to lack of data, volatility of the input or lack of stable historic trends;

(c) **Medium:** Our ability to forecast the input is reasonable, through a combination of data availability and either low volatility or the presence of usable historic trend analysis; and

(d) **High:** Our ability to forecast the input is good, through availability of data and known behaviours.

238 It is not proposed that the above categories be changed for an ex ante / ex post methodology applicable to incentives during the RIIO-T1 period.

National Grid's ability to control inputs to the energy and constraint models

239 We have a number of tools at our disposal to manage or influence the requirement for, and cost of, the actions we take for system operation purposes. The greater degree of control, the more suitable a tool is likely to be for incentivisation. However, not all tools are applicable to all model inputs. Depending on the model input, there may be sub-components that have varying degrees of control, and hence varying suitability for incentivisation. In the current ex ante/ ex post methodology, the tools that we consider to be at our disposal are as follows:

Generic assessment criteria for National Grid's ability to forecast inputs

Tool	Extent of National Grid's control	Areas for incentivisation
Balancing Mechanism (BM)	We could be seen as a price taker in the BM, although our actions as sole counter-party can influence submitted prices in subsequent settlement periods. Also, we can trade-off delivery of required volume of actions between pre- and post-gate closure to deliver value.	Trading strategy
Trades	We can enter into forward trades with counterparties to buy or sell energy for 'energy' or 'system' reasons.	Trading strategy; Contracting approach
Balancing Services contracts	We can enter into agreements with counterparties for the provision of ancillary services or to manage power station output levels.	Trading strategy; Contracting approach; Development of ancillary services; Enhancing pool of available service providers
Transmission system planning/ operation	We can keep our approach to planning and operating the national electricity transmission system under review.	Innovation in planning and operating the national electricity transmission system; Development of relationship with other Transmission Owners
Changes to operating policy	We can refine our approach to determining operational requirements (such as reserve holding) by changing its modelling approach or in light of experience	Development of operating policy
Changes to industry Codes	We can propose changes to industry codes where we believe such change would better facilitate their aims.	Increased co-ordination and efficiency between code parties
Information provision	We can work with the industry to identify information that could be made available	More effective functioning of market with regard to system

Tool	Extent of National Grid's control	Areas for incentivisation
	to participants which might deliver more effective market information.	operator actions

240 It is envisaged that the types of tools set out above will remain in existence in some form, and therefore continue to be at our disposal, over the course of the RIIO-T1 period. We will however continue to innovate during this incentive period and develop new tools that might assist us in further reducing operational costs thereby providing additional value to the consumer. Any new tools are likely to fit within one of the categories as described above and therefore there are no changes proposed to these criteria.

241 Within the current methodology, the extent to which we can use the tools available above to influence the input is considered and given a rating, as follows:

(a) **None:** We have no ability to use the tool to influence the input;

(b) **Low:** Our ability to use the tool to influence the input is restricted in timeframe and scope;

(c) **Medium:** Our ability to use the tool to influence the input is good in some areas (e.g. required volume) but limited in others (e.g. small pool of available service providers impacting price); and

(d) **High:** Our ability to use the tool to influence the input is good in most areas (e.g. required volume and range of available service providers).

242 It is not proposed that the above ratings be changed for an ex ante/ ex post methodology applicable to incentives during the RIIO-T1 period.

Approach to Assessment

243 Within the current methodology, the assessment of energy and constraint cost drivers is structured in such a way that six categories have been chosen to provide a framework within which drivers of costs can be considered. These categories are:

(a) Generation availability (whether generation is not on outage, and can be included in a 'fundamentals' model to determine how it would run in a particular period);

(b) Generation running (how available generation would run in light of market fundamentals);

(c) Demand level (factors which feed into the overall demand);

(d) Demand volatility (factors which drive rapid changes in the demand profile);

(e) Transmission availability (the extent to which transmission equipment is available to transport power – i.e. not on outage); and

(f) Transmission capability (the physical capability of available transmission equipment to transport power).

244 In addition to the above, we propose that a separate interconnector category be created. Towards the end of the RIIO-T1 period, the capacity of interconnection is expected to have doubled capacity today, reaching 7.5GW of installed capacity. Interconnectors must therefore be recognised in their own right as they can have a significant impact on, for example, constraint volume and consequently the cost of managing the system.

245 The determination of the drivers of interconnector behaviour along with the reassessment of inputs from the current methodology is set out below.

Reassessment of model inputs and drivers

246 To facilitate the implementation of a longer term incentive framework, it is critical that the models which determine the cost target fully reflect and are consistent with the ex ante/ ex post methodology. This is so that the incentive on the NETSO remains focused on those elements that we can reasonably control and/ or forecast. During the current scheme, there have been a number of instances identified where inaccuracies in ex ante model inputs result in a discrepancy between model output and actual system conditions. This in turn means that the NETSO and consumers are exposed to windfall gains or losses as this variance is not down to any action that we may or may not have taken but purely due to model inaccuracy.

247 This issue is particularly pertinent for the unconstrained run of the Constraint model (described further in the ‘Constraints Modelling’ section below) which looks to determine a schedule of generation running, and interconnector flows, to meet a forecast demand. This initial run of the model produces a market-determined generation ‘baseline’ against which BM actions are then taken by the model to resolve constraints on the system. The difference between these two model runs, then produces a target cost of constraints against which we are incentivised to reduce costs.

248 It is therefore imperative that the first run of the model, effectively determining which generating units will run on any given day (plus interconnector flows), is as accurate as possible i.e. that it reflects what we see, and are required to operate, in reality on the system. Any inaccuracy in this first model run may result in costs either being artificially inflated or reduced by the model when resolving constraint boundaries during the second model run, particularly if the generating unit(s) concerned typically impact upon a constraint boundary. This in turn means that we can be either exposed to a cost in reality which is not recognised by the modelled target or, conversely, that the model provides a cost that we have not had to incur. Ultimately, therefore, model inaccuracy can result in, and has resulted in for the current scheme, windfall gains and losses.

249 We therefore believe that scope for windfall gain or loss to the consumer as a result of modelling inaccuracy is reduced by the re-assessment of a number of modelling inputs from an ex ante treatment to an ex post treatment. In particular, this re-assessment of inputs will serve to better meet the following principles:

(a) Increase transparency of the models for the industry by employing less ex ante data derived on the basis of assumptions that can be called into question;

(b) Provide models that are easier to understand by the industry because the input data that cannot be modelled accurately is replaced with actual outturn data;

(c) Increase modelling accuracy for those areas that we cannot control and/ or forecast; and

(d) Maintain and focus the incentive on us to reduce those costs of balancing the system that are within our control over the RIIO-T1 period.

250 The inputs that we are looking to reassess from an ex ante treatment to an ex post treatment are set out in detail below. These are:

(a) Generation availability;

(b) Generation Running - commissioning plant;

(c) BM Pricing or Wholesale power price mark-ups; and

(d) Interconnector flows.

Generation Availability

251 To better align the ex ante/ ex post methodology with the constraint modelling methodology, and reflect the extent to which we can control or forecast this input, it is proposed that generation availability be reassessed from an ex ante to an ex post input. We propose that the source of data for this input be outturn MEL data which would mean that the requirement to have long-term generation availability, and OC2 data as an input to the model, is negated.

252 Generation availability is a key input to the Constraint model. In the current scheme methodology for the ex ante or ex post treatment of modelling inputs, both long-term and short-term generation availability are determined as ex ante inputs to the models. This is despite:

(a) Long-term generation availability (OC2 data) currently being assessed as ‘low-medium’ in terms of our ability to forecast and control this input; and

(b) Short-term generation availability (MEL data) currently being assessed as ‘none’ in terms of our ability to forecast and control this input

253 The reasoning behind ex ante treatment in the current scheme was in recognition that we do have the ability in theory to contract with a generator in order to influence its availability e.g. by contracting with a generator to bring forward or delay an outage such that constraint costs can be reduced. However, in practice the scope for taking such action is small given the level of change to generator outage programmes within year and lack of

competition in this type of service provision can make it difficult for us to influence the price we would have to pay.

254 Currently, for long-term generation availability, OC2 data is input to the model at the start of each incentive year on an ex ante basis. This is a direct input to the Constraint model and is used to determine the plant available for the model to utilise in either the unconstrained or constrained runs. OC2 data is subject to significant change throughout a 1 year period, for example the 1 year ahead outturn success rate for submitted OC2 data for 2011/12 was only 5% for significant outages[24]. This means that a very small proportion of the significant planned outages at the year ahead stage were taken as submitted by generators.

255 Further, the extent to which we can forecast this data in reality is actually low, rather than low-medium, due to the inability to apply historical data to form any kind of trend and the volatility of the dataset within year. As an example, gas generating plant maintenance programmes tend to be based upon operating patterns and running hours of the plant and are therefore sporadic in nature. These factors contribute to the difficulty in forecasting generator outage programmes.

256 Similarly, for short-term generation availability, unplanned outages are currently an ex ante input entered into the model as a stochastic simulation based on normal historic breakdown rates (estimated for each plant). In the event that a generator is available to run within the model but not available in reality (and vice versa) then the target cost may be inaccurate and windfall gains and losses can occur. Given the random nature of generator faults, we can neither control nor forecast when these may occur. They also have the potential to impact significantly on actual balancing costs which should be recognised by the cost target model.

257 The re-assessment of generation availability to ex post treatment will significantly increase modelling accuracy for longer term schemes and reduce scope for windfall gains or losses by, for example, more accurately representing within the model:

(a) New generators that are late in commissioning their plant;

(b) Existing generators that opt to put their plant into ‘preservation mode’[25]; and

(c) Unplanned generator faults.

258 To provide an example, 4 generators have declared to National Grid within year that they are placing their plant in preservation mode during the current incentive scheme period. This means that those plants are unavailable to National Grid for system operation in reality but temporarily remain available within the model (until the true availability is captured in the model by an

[24] Significant outages are defined as full unit outages apart from small hydro units and OCGTs, excluding weekend outages or outages of a day or less.

[25] This is where a generator does not necessarily reduce its Transmission Entry Capacity (TEC) but chooses to withdraw from the market in the short to medium term.

annual update of OC2 generator data input). In addition, those generators that become unavailable during the scheme may be required to manage system constraints and therefore we would seek to contract with this generation to become available for a period of time. As it stands the model would not recognise this scenario or model this requirement as a cost within the constraint target, thereby underestimating the cost to manage these types of constraint.

259 Most importantly, this re-assessment of generation availability does not remove the incentive from us to reduce system operation costs as we are still required to forecast generation availability on an ex ante basis in order to make decisions on contracting for balancing services, trading and outage optimisation ahead of real time. One concern with this approach might be that if generation availability were to be ex post, we have the ability to influence this input and therefore impact upon the incentive cost target e.g. through contracting with a generator. Two constraint contracting scenarios are considered here:

(a) We contract with a generator to be available and generate when it was not originally available in the market to manage an import constraint; and

(b) We contract with a generator to generate at a pre-determined or capped output to manage an export constraint.

260 Under option 1, if generator availability is determined ex post, actual (contracted) MEL data of the unit would be employed in the model and it becomes available for the constrained run. In an import constraint scenario, the contracted generator is required to run to manage the constraint. Therefore if the contracted MEL in this situation had not been used (i.e. the non-contracted MEL of zero had been employed), the unit would not be available in the Constraint model to resolve the constraint in the constrained run. This means that the model would not produce a target forecast cost to manage the constraint in the balancing mechanism to which the cost of actually contracting with the unit is compared. So the use of actual (contracted) MEL in this instance results in a more appropriate outcome from a modelling perspective than the use of a non-contracted MEL of zero. It also maintains the incentive on us to negotiate a contract at the lowest cost as the generator will seek to receive a premium for providing availability when it was not originally economic to be so.

261 Under option 2, the MEL parameter that a generator submits during the contracted period should be unchanged from the original or non-contracted MEL level. In fact, when we contract with a generator for a capped PN contract to manage constraints, we ensure that the relevant MEL parameter is still submitted to provide confidence that the unit would otherwise be available, and to provide the option for effectively unwinding the contract (i.e. increasing output beyond the cap) if necessary e.g. to manage a wind-driven requirement. This type of contract is the most common of the two options because it is used to manage export constraints (particularly in Scotland) which again are more common on the system.

262 Employing ex post MEL will also more accurately represent the system impact, and therefore costs, of any generator unplanned faults. Currently the

model will not recognise when a generator is actually unavailable due to a fault, in the same way that within year changes to OC2 data are also not captured. Again, this serves to reduce the scope for windfall gain or loss resulting from circumstances that are outside of our control.

263 Similarly, whilst the use of ex post MEL reduces the scope for windfall gains and losses throughout the scheme, it does not reduce the risk of taking constraint contracting decisions. For instance, in an export constraint scenario where we have contracted to constrain generation off we are not protected by the use of ex post MEL in the model if something else in the group falls off. Correspondingly, in an import group where we have contracted with generation to run and something cheaper becomes available, we are not protected by ex post MEL. The incentive to contract ahead of real time and the risk associated with contracting decisions is therefore maintained.

Generation Running – Commissioning Plant

264 Generation running is an ex ante element of the constraint cost model and is determined by the unconstrained run of the Constraint model where generator PNs are forecast by the model based on market fundamentals to meet a system demand. This process will not change for the incentive scheme during the RIIO-T1 period, however we again seek to further remove potential windfall gains or losses associated with this model run. In particular, the treatment of commissioning generators within the model can result in, and has resulted in during the current scheme, windfall gains and losses to consumers.

265 Therefore, in order to reduce the possibility of wind fall gains or losses, it is proposed that actual ex post commissioning generation output be input to the model until such time that they are fully commissioned. The basis for this is that a commissioning generator will not generate according to market fundamentals and hence its output is not possible to be accurately forecast by the model. These generators are also not controllable by National Grid as the commissioning schedule dominates the generator’s behaviour.

266 During its commissioning period, a new generator’s output will be naturally variable as the plant is being tested and will be prone to unplanned events such as trips or fast de-loads. Neither will it necessarily follow market fundamentals (e.g. fuel prices) in relation to its decision to generate. In essence the commissioning test programme will dominate the output of the plant and will be unique to each generator.

267 Currently, as set out above, the Constraint model uses OC2 data input at year ahead to determine whether a generator is available to use either in the unconstrained or constrained runs of the model. The commissioning generator will input to OC2 the date from which it anticipates to operate (i.e. the date that it can physically generate) but the date upon which the generator is actually commercially available (and therefore available to the NETSO) may be much later than the initial stated date. This means that the model will be able to run the generator in the unconstrained run when in reality the generator is not available or running. This then has an impact on the system constraints observed by the model, the outcome of the constrained run and therefore the cost of constraints. An example for the current scheme is the new Pembroke generator where the Constraint model output showed that there were

constraint costs being incurred in the South Wales constraint zone when in reality the generator was not available or running.

268 The availability of this generator within the Constraint model but not in reality has resulted in:

(a) The Constraint model attributing significant costs to a constraint that in reality did not exist i.e. a windfall gain to National Grid during the commissioning period; and

(b) Based on the ex-ante availability, the Constraint model was running the generator for significant periods and hence displacing other generation.

269 A significant number of new generators will be commissioned over the course of the RIIO-T1 period which in turn presents the possibility for windfall gains and losses in the scheme, such as those experienced with Pembroke this year. The extent and direction of windfall will depend on the location of the generator and system congestion of the zone in which it connects. Whilst the proposed ex post treatment of generator availability using actual MEL data of generation (as set out above) goes some way to reducing the issue, the MEL of a commissioning generator can still significantly differ from its actual output. In addition, we do not rely on the output of a plant during its commissioning period from a system security perspective until the commissioning process is complete and a period of stable running has been demonstrated.

270 The use of actual metered output of commissioning generation will therefore improve the accuracy of constraint modelling associated with such generators but also better reflect the way in which we treat commissioning plant as NETSO. More detail as to how this input will be incorporated into the constraints model is set out in the ‘Constraints Modelling’ section below.

BM Pricing/ Wholesale Power Price Mark-Ups

271 In order to reduce the potential for windfall loss or gains over an 8 year framework through modelling inaccuracy, and to recognise the lack of control that we have over submitted BM prices (and NIV), we consider that BM pseudo price[26] within the energy model should be changed from an ex ante relationship using ex post variables to a single ex post input.

272 Currently, the extent to which BM bid-offer prices are set by generators relative to the wholesale price is an ex ante input to the energy cost target models in the form of BM pseudo price. In particular, BM pseudo price is determined by the Energy Imbalance (EI)[27] model albeit using ex post variables via a relationship that is determined ex ante. These ex post variables

[26] The BM pseudo price is a representation of the volume weighted average price that would be paid to resolve Net Imbalance Volume in a particular half hour period. More detail as to how this is calculated can be found in Appendix A: Energy Model.

[27] The calculated Energy Imbalance costs are the least cost method of resolving NIV via actions in the BM.

are Single Price Net Imbalance Reference Price (SPNIRP) as defined in the Transmission Licence[28] and Net Imbalance Volume[29] (NIV).

273 The reason for using these variables is that SPNIRP represents the underlying power price which is then reflected through to BM pricing. NIV is used because BM pseudo price will differ during different market lengths e.g. the shorter the market the larger the volume of actions required and the further along the price 'stack' these prices will be. A variable within the modelled relationship therefore describes the change in relationship between BM pseudo price when the market is long or short.

274 This input to the model is currently treated as an ex ante input despite being assessed as 'low-medium' in terms of our ability to forecast this input. The rationale for ex ante treatment for the current scheme was that whilst trends in wholesale power prices would not be a reliable indicator of future price levels, the extent to which bid-offer prices are set relative to the wholesale power price was more likely to be suitable for trend analysis. The result being that a derivation of an historical trend can provide a forecast of future prices, given the level of power price and market length.

275 However, experience from the current scheme has demonstrated that determining and applying such a forecast of BM pseudo price is not as straight forward as applying a historic trend. EI outturn costs are calculated as the sum of the least cost, feasible, submitted bids or offers required to resolve NIV (BM pseudo price multiplied by NIV). The current scheme determines the target EI costs by multiplying ex post NIV with the modelled forecast BM pseudo price. The current BM pseudo price model for 2011/12 does not provide an accurate reflection of prices, which has resulted in a £36m increase between target and actual EI costs and therefore a windfall gain to National Grid.

276 The only tool that we have to reduce the actual cost of resolving EI is to trade energy ahead of real time. However, during the current scheme period we have not traded significant volumes for energy ahead of time due to the minimal gain that this may produce against the risk of NIV forecasting error. Moreover, due to the design of our internal costing methodology, any value created through forward trades to resolve NIV would be 'visible' via the margin model component within the overall energy model. Given that NIV and SPNIRP values are ex post inputs to this model, the £36m difference between target and cost solely results from model inaccuracy in the BM pseudo price relationship.

277 BM pseudo price is used in several components of the energy model aside from just EI costs[30] and therefore any error incurred as a result of the modelled ex ante relationship then manifests itself through to those other models and amplifies any windfall gain or loss. The issue of modelling error is

[28] The SPNIRP calculation can be found in Schedule A to Special Condition AA, part B paragraph B4 of the National Grid Electricity Transmission Licence.

[29] Net Imbalance Volume is often referred to as market length.

[30] It is also used in the Margin Cost model as part of the operating reserve price model, in the calculation of the out of merit price of margin. This price is then used in the Wind, STOR, Static Response and Firm Frequency Response Displaced Margin Cost models along with the Constrained Margin Management and BM Start-up models. The BM pseudo price is also used in the Frequency Response price model.

particularly pertinent over the course of a longer term incentive framework where the application of historic trend data may not be sufficient to provide a robust forecast of a key model input, particularly as the operating environment changes.

278 It has therefore been demonstrated that we are not able to employ trend analysis to accurately forecast BM pseudo price as an input to the Energy models and thus the ability to forecast this input is reassessed as low.

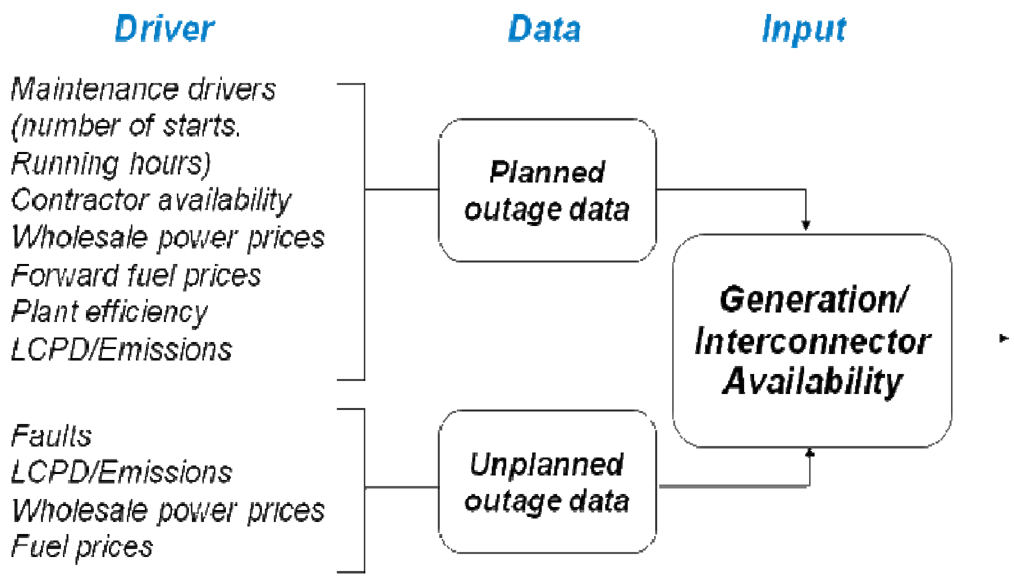
279 The ex post treatment of this input also aligns, and is consistent, with ex post treatment of BM price in the constraint model.

Interconnector Availability

280 Towards the end of the RIIO-T1 period, the capacity of interconnection is expected to have doubled to ~7.5GW. Currently interconnectors are assumed to be available on a permanent basis within the Constraint model.

281 The drivers of interconnector availability are similar, although not identical, to those already set out in the ex ante/ ex post methodology for generation availability and therefore this category of input is proposed to be expanded to include interconnector availability (the diagram below illustrates the amended version).

Drivers of generation and interconnector availability



282 For consistency, in the same way that generation availability is proposed to be reassessed to an ex post input, interconnector availability is also proposed to be input to the constraint model on an ex post basis. This, again, removes some of the issues experienced during the current scheme. For example, the long term unplanned outage of the Moyle interconnector has had a significant

impact on the actual constraint costs incurred by National Grid, but these have not been reflected in the constraint model target. It also looks to reflect that our ability to forecast and control this model input is low thereby further focusing the incentive on those elements that we can control. The model will be more accurate where interconnector availability is treated as ex post thus reducing the scope for windfall gain or loss for an input that is outside of our control.

283 This reassessment of treatment from ex ante to ex post does not reduce our incentive with regard to using the interconnectors for managing and reducing balancing costs. It merely ensures that interconnectors are correctly represented within the model which, if represented incorrectly, can result in large windfall gains and losses.

Interconnector Flows

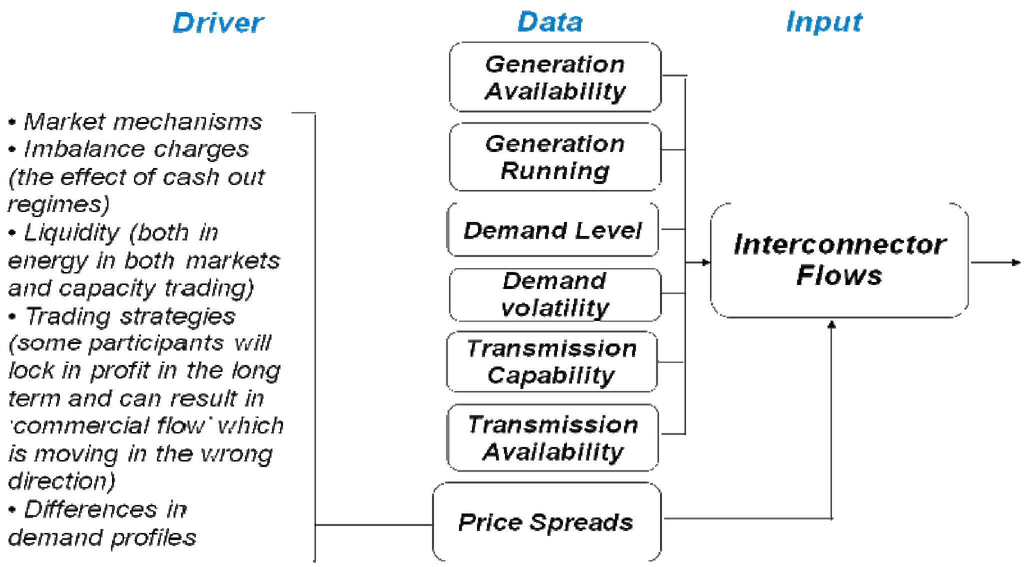
284 Given the anticipated increase in interconnector installed capacity by 2021, the potential changes in flow across all interconnectors will be ~14GW (full import to full export). It is therefore imperative that behaviour of interconnectors is modelled accurately over the incentive period as they can have a significant impact on the costs that we face to manage the system.

285 Within the current scheme model, flows on the interconnectors will occur only if the price differential between the importing and the exporting market is larger than a pre-determined wheeling charge. The model was calibrated at the start of the scheme by adjusting the wheeling charge to match annual historic interconnector flows. However, these wheeling charges are not necessarily an indication of future flows. Moreover, the non-GB market is represented in the model by a simple generation stack, comprising the predominant fuel type(s) in that market (e.g. French market represented by nuclear and gas) to meet a simple demand profile.

286 Experience with operating under the current scheme shows that the model is not able to accurately represent interconnector flows due to the number of drivers potentially influencing this input. The drivers of interconnector flows are set out in the diagram below. Most of the drivers comprise the original six cost categories of BSIS costs as the relative levels of these inputs in each market either side of an interconnector may drive flows across that interconnector in a particular direction.

287 In addition to these drivers, there are additional drivers to take into account market differences and therefore price spreads between the two markets.

Drivers of interconnector flows



288 The above diagram goes some way to displaying the complexity surrounding the drivers of interconnector flows and therefore indicates that the current modelling solution is too simplistic. This has resulted in modelling inaccuracies and therefore potential for windfall gains and losses. Our ability to forecast or control these drivers, particularly for the non-GB market, is low. This issue is compounded when interconnector flows may be influenced by factors that do not originate in the market with which the interconnector connects e.g. events on the German system may have a knock-on impact to flows on the French-UK interconnector.

289 Therefore, in order to increase modelling accuracy, and recognising that our ability to forecast or control interconnector flows pre interconnector gate closure[31] is low, it is proposed that this input be assessed as ex post. Given that we are able to call upon balancing services on interconnectors post gate closure, it is proposed that flows on each interconnector are input to the model as the gate closure nominated flows rather than ex post metered quantities, thereby excluding any of our actions. This change should mean that interconnectors are more accurately represented in the model than at present and reflect flows as the market has determined them.

290 Thus, any action that we take on an interconnector to manage system costs will be determined by the difference in the unconstrained and constrained run within the Constraint model where actual (gate closure) interconnector flows are used to determine the unconstrained run.

291 Changes to SO-SO cross border arrangements may be brought about by development of the European Network Codes and, in particular, the Network Code on Capacity Allocation and Congestion Management (CACM). It may

[31] Following the introduction of the Use It or Lose It arrangements, National Grid cannot take action on any interconnector pre-gate closure.

therefore be necessary to reassess the treatment of this input at some point in the future.

Summary of treatment of inputs

292 The table below summarises the conclusions drawn in the sections above where the proposed amendments or additions to the existing methodology have been highlighted in red. No further changes are proposed to the existing methodology and therefore all other inputs will remain as originally assessed.

Summary of proposed treatment of cost drivers

Generation:	Forecast Confidence:	Treatment in models:	Degree of Control:	Suitable for incentivisation?
Long Term Generation Availability (OC2)	Low - medium	N/A[32]	Low - medium	No
Short Term Generation Availability (MEL)	None	Ex-Post	None	No
Commissioning Generator Output	Low	Ex-Post	Low	No
Generation Contribution to NIV	Low	Ex-Post	None	No
Generator Fuel Prices	Low	Ex-Post	None	No
Wholesale Power Prices	Low	Ex-Post	None	No
Generator Efficiency Factors	Medium	Ex-Ante	None	No
Free headroom	Low	Ex-Post	None	No
Renewable generation running	Low	Ex-Post	None	No
Nuclear generation running (for footroom model)	Low	Ex-Post	None	No
Frequency response/reserve requirements	High	Ex-Ante	Low	Yes
Largest generation loss	High	Ex-Ante	Low	Yes
BM Pricing/wholesale power price mark-ups (for energy models)	Low	Ex-Post	Low	No

[32] Given that MEL data is proposed to be treated as ex post, there is no longer a requirement to use OC2 data within the model as the outturn MEL data will reflect real time generator outages.

BM Pricing for constraints modelling	Low	Ex-Post	None - Low	No
Interconnectors:				
Interconnector flows (pre-gate)	Low	Ex- Post	None	No
Demand:				
Demand Level	High	Ex-Ante	None - Low	Yes
Demand volatility	Medium	Ex-Ante	Low - medium	Yes
Demand contribution to NIV	Low	Ex-Post	None	No
Largest demand loss	High	Ex-Ante	Low	Yes
Transmission:				
Transmission availability (OC2)	Medium	Ex-Ante	Medium	Yes
Transmission capability	Medium - high	Ex-Ante	Medium	Yes
Other:				
RPI	Low	Ex-Post	None	No

Ex ante Inputs – Treatment within the models

293 Whilst the model inputs not mentioned above remain unchanged from the original methodology in terms of ex ante or ex post treatment, we may still be proposing a different treatment within the modelling methodology itself. For example, whilst an input may continue to be treated as ex ante within the methodology, we may propose that it is input to the model at more regular intervals to ensure that inputs are as accurate as possible whilst still maintaining an incentive on us to reduce operating costs. All ex ante inputs will also be reviewed in order to ensure that they remain to be a robust input source to the models throughout the RIIO-T1 period. These will be explained in more detail in the relevant ‘Energy Modelling’ and ‘Constraints Modelling’ sections below.

BSIS: Energy Modelling

Overview

294 This section sets out the principles of the energy cost target model for BSIS over the RIIO-T1 period. The current energy sub-models are to be enhanced and expanded to more closely represent the costs of operating the network and provide a more accurate cost target. For the first 2 year phase of the scheme, the enhanced models should remain sufficiently robust, however, for the second and third phases we recognise that changes to cost drivers will require the models to be developed further.

295 In this section, we therefore set out the developments that may be required over the longer term and the drivers for doing so. When proposing developments to the current model, the modelling principles set out in the 'BSIS Introduction' section and the review of model inputs in the 'Ex ante or Ex post Treatment of inputs' section are considered. Further details regarding the performance of the current models and therefore the rationale for enhancement can be found in Appendix A to this document.

Background to the Energy Model

296 During the SO Review in 2010, prior to the current scheme, the energy models were developed and extended in order to be applicable to, and representative of, a 2 year period (such that a longer term scheme could be implemented). This included facilitating the introduction of ex post variables and undertaking investigations on improving the modelling of cost drivers that have shown, as indicated by previous analysis undertaken, to have a noticeable impact on modelled costs. Where possible, the models were also simplified from historic versions.

297 The energy model comprises the following cost target sub-models:

(a) Energy Imbalance

(b) Margin

(c) Frequency Response

(d) Fast Reserve

(e) Footroom

(f) Reactive Power

298 In most instances, regression analysis has been used to represent the variables and model the relationships between BSIS cost drivers and the costs themselves. This type of analysis facilitates an understanding of how a dependent variable changes when independent variables are altered (e.g. the extent to which BM Prices are affected by wholesale power price). The impact of introducing different variables can also be assessed using regression analysis in order to determine which bears the greatest relationship to the dependent variable (or BSIS cost) in question.

299 The ex post/ex ante approach to incentivisation means that the relationships between the chosen variables within the models (regressions) form part of the current scheme. Thus, each model includes an ex ante defined relationship and these defined relationships are being used throughout the duration of the current scheme to calculate an ongoing scheme target with use of both ex ante and ex post inputs.

300 The current models are described in more detail in the Energy Modelling Methodology[33] which was agreed with Ofgem prior to the start of the current scheme. The current scheme model methodology was based around linear model design with coefficients developed from regressions using datasets from the previous five to seven years (up to March 2010).

301 We have monitored the performance of the current scheme models on an ongoing basis since the scheme commenced on 1 April 2011. The majority of the models are performing generally as intended. A more detailed assessment of the performance of all the models can be found in Appendix A to this document. The developments that we propose to make to the current models are based upon experience from current performance and in light of possible future developments. These are discussed further below.

Proposed Modelling Approach

High Level Model Design

302 During the 8 year RIIO-T1 incentive framework there will be significant changes to both the energy market and to the types of providers of the services we procure. This will directly impact both the volume and prices of services that we use to balance the system and therefore the models that are used to forecast cost targets for the energy components of BSIS.

303 Therefore the proposed approach for the first phase of the scheme (1 April 2013 - 31 March 2015) is to employ an enhanced version of the modelling methodology that has been used for the current scheme. Enhancements will be made using analysis of the current scheme performance and assessments around the impacts of future drivers. However, during the RIIO-T1 period it will be necessary to develop the energy modelling methodology as the new drivers begin to impact the source and costs of balancing services that we procure. This will ensure that the strength of incentive is maintained as the services that we procure can be accurately represented in the models and therefore the modelled cost targets.

304 As set out above, the models comprise regression coefficients which are based upon historic datasets. In order to reflect the most recent trends in system operation and market behaviour, we propose that these coefficients are updated at the end of each year within the 8 year framework on a rolling basis. This update will form part of a wider annual model review process which is set out in more detail in the 'Annual Model Review' section below.

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[33] This methodology can be found on our website at: http://www.nationalgrid.com/NR/rdonlyres/9A536B73-7545-4484-9BFC-D27D6E5CBD89/47901/Energy_Modelling_Methodology_Issue1_18thJuly2011.pdf

Developments during the RIIO-T1 period

305 The key drivers that we consider are relevant to the energy models during the RIIO-T1 period are:

(a) Increased Interconnector capacity;

(b) Increased renewable penetration;

(c) SQSS change for increase in largest loss to 1800MW in 2014;

(d) Increased reserve volumes and the types of service providers (including demand side);

(e) Increased response volumes and the types of service providers (including demand side); and

(f) Changes in generation mix, including closure of plants that are opted out of the LCPD.

306 The timing and significance of these drivers will differ, as will the resultant impact on the inputs and therefore the energy models themselves. The extent of the impact of these drivers presents uncertainty over the next 2 to 4 years and therefore efforts to incorporate these elements into the models at this time would be inefficient. Further operational experience will be required to assess exactly how any changes should be made to reflect any market developments.

307 We propose to focus analytical effort on delivering a model for the first 2 year phase of the scheme.

Significant Model Review Process

308 As set out above there are many identifiable areas of uncertainty over the RIIO-T1 period. It can also be expected that there will be a number of areas that will drive uncertainty that have yet to be identified and may also impact the model performance and require changes to both the model relationships and the model regressions.

309 As stated above, the model methodology will be subject to an annual regression review to ensure that the most recent operational data is used. This will ensure that trending shifts in the markets will be correctly reflected over the 8 year period. However, some changes in the markets will be more significant and will create a step change effect on cost drivers that will not have been considered in the modelling. An example is the implementation of EMR and the potentially significant impact that this may have upon the types and prices of the services that we procure.

310 Under these circumstances it is proposed that the review points between phases be employed to assess impacts, and therefore explore solutions, to ensure that models continue to accurately model the operating environment. This process was described in more detail in the 'BSIS Design and Governance' section above. Any fundamental review of the regression coefficients will require the agreement of:

(a) Input source data;

(b) Dataset length in years;

(c) Data training sets;

(d) Methods of regression analysis; and

(e) Model design.

Proposed Model Design

311 Appendix A to this plan sets out more detail regarding:

(a) An overview of the current models; and

(b) Model performance during the current scheme.

312 Based on the above, the section below sets out each component of the energy model in terms of the approach for further development to apply to the first phase of the scheme. Further work identified and required to be undertaken for the following two phases is also described throughout this section.

Energy Imbalance

313 The Energy Imbalance model has proved to be the least accurate element of the overall energy model for the current scheme. This is attributable to the modelled relationship between BM pseudo price[34], Net Imbalance Volume (NIV) and power price (SPNIRP). Due to warmer weather over winter 2011/12, and the prominence of coal over gas generation, the regression coefficients within the model have inaccurately modelled the BM pseudo price (please see Appendix A for further assessment detail of the current model).

Identified Model Amendments

314 As discussed in the 'Ex post or Ex ante Treatment of Inputs' section above, the most accurate approach for deriving an Energy Imbalance cost target is to employ an ex post BM pseudo price. Using an ex post BM pseudo price multiplied by ex post NIV to give target energy imbalance costs reflects how outturn energy imbalance costs are calculated in reality.

315 The Energy Imbalance model outturn cost is the sum of the least cost submitted, feasible bids or offers required to resolve NIV. The modelled cost presents a target against which we are incentivised.

316 The only way to resolve Energy Imbalance at a cost lower than the calculated outturn cost is to trade energy ahead of time. However, due to the costing methodology used within National Grid to categorise SO actions, these trading actions and the cost associated with such actions would be categorised as a margin model component rather than an Energy Imbalance component. Therefore in reassessing BM pseudo price as an ex post input does not reduce the incentive on us to seek savings against submitted BM prices. Any benefit that we are able to derive in this area would be demonstrated as a

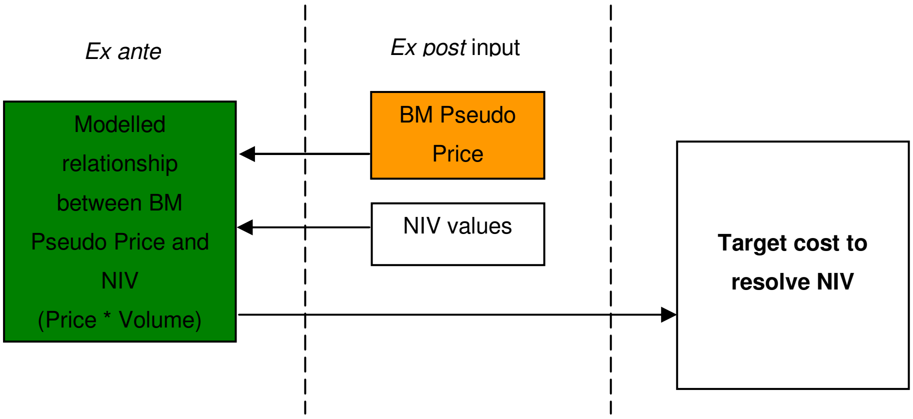
[34] BM pseudo price is described in more detail in Appendix A to this document.

negative cost in the margin model if trading actions were successful in outperforming the BM pseudo price.

317 The BM pseudo price input is also employed in other energy sub-models, hence moving to an ex post BM pseudo price will also improve the accuracy of those other areas within the overall model.

318 The revised Energy Imbalance model is demonstrated by the diagram below. It should be noted that since BM pseudo price is to become an ex post input, SPNIRP is no longer required as an input to this model[35].

Revised Energy Imbalance Model



Margin Model: Operating Reserve

Identified Model Amendments

319 For the first two year phase of the 8 year framework, the current model design of the Operating Reserve volume and price elements of the margin model will be used. However, as set out above, we propose to change BM pseudo price to ex post as an input to the operating reserve model.

Ongoing Model Development

320 As the volume and variability of renewable generation grows and interconnection with other markets increases there will be a requirement to review the Operating Reserve volume model. Currently the model considers that Operating Reserve is required during daytime hours and that this requirement is constant throughout those times, however, higher wind and interconnector variability will challenge this historic modelling assumption.

321 In addition, the model currently includes a monthly wind adjustment factor such that Operating Reserve volume is adjusted according to the volume of wind generation on the system at any point in time. In order to provide

[35] SPNIRP was used by the model to explain changes to BM pseudo price given the level of NIV.

increased accuracy, this wind adjustment factor may be enhanced such that a half-hourly adjustment is made.

322 The current wind adjustment and reserve for policy only considers system wide total wind output, however over the course of the scheme there may be a requirement for more locational reserve holding in areas of high wind. The implementation of reserve for wind policy is continually changing as further operational experience is gained. It is therefore important that this is appropriately reflected within the volume model, particularly as larger onshore and offshore wind farms connect to the NETS.

323 The increase to largest infeed loss to 1800MW will take effect in 2014 and will require an increase in response holding. This increase in response holding will in turn require a larger volume of margin to enable that response provision. Amendment to the model will be required as historical datasets will not provide appropriate forecasts following this change. Further work will be required on this, and the above areas, over the next 2 years.

Margin Model: BM Start-Up

Identified Model Amendments

324 For the first phase of the incentive scheme, the current BM start-up model will be employed with the regression coefficients updated to reflect the most recent datasets for the existing variables.

Ongoing Model Development

325 Going forward, simple forecasting based upon historic actions is unlikely to be the most effective forecasting methodology for this cost element. Alternatives based around a total reserve requirement model may better reflect the true volumes of BM start-up required. A marginal fuel type variable could be incorporated into the model, for example, in order to more accurately reflect the type and therefore cost of plant used for margin actions.

326 It is possible that, in the short term, a number of low efficiency gas-fired power stations plant become “commercially cold” requiring a longer start up time than currently experienced. This could see BM start-up contracts being agreed to gain access to these units such that they become available in BM timescales. These contracts are currently in place with a number of coal and oil units and therefore the way in which these ancillary services costs are modelled will require review.

Margin Model: Short Term Operating Reserve (STOR) Cost

Identified Model Amendments

327 For the first phase of the scheme it is proposed that we employ the current modelling methodology whilst updating the regression coefficients with the latest datasets. Development in this area will focus on improving the intelligence of the model such that contracting benefits can continue to be captured whilst retaining an appropriate strength of incentive to create further value.

Ongoing Model Development

328 The STOR volume and cost model currently employs a fixed ex ante price and volume forecast, however this will not continue to be suitable over a longer timeframe as the providers and availability of the STOR service change. The market price for STOR and volumes available are likely to change significantly and hence a change to the modelling methodology will be required.

329 The STOR market is a dynamic market with a number of providers using different technologies to provide this service to us. The market has also grown in previous years, which is in part due to the work we have undertaken to promote competition and in part due to the perceived value in the market.

330 The model will require development such that any changes to the STOR market as described above can be accommodated. This will maintain the incentive on us to continue to promote competition in STOR, in order to deliver benefit to consumers.

Margin Model: Constrained Margin Management (CMM)

Identified Model Amendments

331 In the short term the current CMM model is suitable for application to the first phase of the scheme with the regression coefficients to be updated with the latest datasets. Whilst the model only represents constraints volumes across the Scotland-England constraint boundary (Cheviot boundary), there are currently no other system boundaries for which CMM is likely to be applicable in the next 2 years.

Ongoing Model Development

332 Beyond a 2 year timescale, there are likely to be other significant margin constraints that require modelling. A further potential development to the CMM model is that it currently employs the output of the Constraint model constraint model to determine the volume of export constraint from Scotland to England. This modelling interdependency will be subject to ongoing review.

333 During the second half of the scheme there is likely to be an interaction between CMM and wind levels, wind reserve requirement and short term system constraints. This is likely to become a locational issue, rather than just a Cheviot boundary issue and hence methodology changes are anticipated in this area.

Frequency Response

Identified Model Amendments

334 The drivers for change to the Frequency Response model include the increased volume and variability of wind penetration and the increase of the largest loss to 1800MW in 2014.

335 The increase of the largest loss to the system will, at times, drive a direct requirement for additional response holding. However, the point at which the increase will be made in 2014 will not immediately result in a change to the amount of response we hold. The increase to the largest loss response holding is directly related to additional new types of generation connecting to the NETS as well as the design of those connections to the system. Until these generation and connection types are realised there will not be a requirement for us to hold the additional response.

336 We therefore propose to implement a temporary ex post largest loss input into the frequency response model to reflect the actual volumes for response holdings. This input would need to be determined by an agreed methodology using historical response holding data and be employed for a pre-determined period of time. Following this period of time, the response holding volume can potentially revert to an ex ante input. We will continue to monitor the impact that the increase in largest loss has on the models as historic variable relationships will not provide an adequate forecast as this input changes.

Ongoing Model Development

337 In the short term the impact of future drivers to the Frequency Response model are limited to the areas identified above; however for the latter phases of the scheme there will be a significant impact to the modelled relationships as a result of market developments.

338 The model currently includes ex ante targets for contracted frequency response services such as static response and Firm Frequency Response (FFR). We will need to ensure that the model can continue to accurately represent and forecast these contracted volumes resulting from changes to the markets for these services.

339 It will also be appropriate to investigate the way in which BM costs are modelled in the Frequency Response model as there are currently separate sub-models for modelling BM bids and offers (to facilitate the provision of primary/ secondary and high frequency response respectively), and separate price and volume elements to determine a total cost. These separate models may become increasingly inaccurate in their ability to forecast our real-time actions whereby the frequency response holding volume will be constantly changing. This volume holding will be subject to:

(a) requirements brought around by demand uncertainty;

(b) interconnector flow changes;

(c) the impact of increased renewable penetration; and

(d) the increase of the single largest loss.

340 Over the duration of the RIIO-T1 period there are likely to be significant changes to the types of frequency response providers and therefore the way in which our required volume of response holding required is met. As the market for this service develops, we will continue to review how the model incorporates different types of providers such as demand side response.

Remaining Energy Sub-Models

341 At the time of submission, further work is underway to identify enhancements to the remaining sub-models. We propose, as a minimum, to update the regression coefficients within each sub-model such that the latest datasets are taken into account for the first phase of the BSIS scheme. We set out below the likely direction of additional developments to be made to these sub-models.

Fast Reserve

342 Various drivers are increasing the holding and utilisation of fast reserve as a balancing tool. Recent operational experience has demonstrated that the fast reserve service is increasingly used to manage ramp rates on interconnectors and the variability of wind at times of low wind generation output. Due to the limited operational experience of such scenarios there will be a requirement to monitor and develop the model as experience is gained. Whilst there is potential for the annual updates to regression coefficients to capture these changes it would be far more appropriate to include the cost drivers into the model directly.

Reactive Power

343 In the medium term the volume of Reactive Power required is unlikely to change significantly. In the longer term volumes are predicted to reduce as Distribution Network Operators take more control of local issues as a result of the Low Carbon Network Fund. Future work will therefore be required to ensure that the volume forecast is accurate following such changes.

Footroom

344 The current model assumes an ex ante fixed price for footroom actions based on historic prices. With an increasing volume of footroom actions required due to factors such as increased wind generation and interconnection, a fixed price based on a history of a lower volume of actions is unlikely to be suitable. A more intelligent price model that uses a price stack to estimate the effect of increasing volume of actions on price may be required.

345 The volume forecast uses ex post inputs of nuclear generation and wind generation output along with ex ante demand to forecast the volume of footroom actions required. Interconnector flows also need to be incorporated as an input to this model which would be included as an additional ex post variable consistent with the proposed constraint model.

346 The volume model is based on the assumption that the footroom requirement is constant across history. Whilst this may be true for the history, the requirement going forward is unlikely to remain static. Recent analysis has indicated that the negative reserve for response conversion factor of 0.7 (1MW of footroom will deliver 0.7MW of high frequency response) is no longer reflective of the level of response being provided by generation on the system.

This level will therefore be reduced to 0.55. With the high response requirement unchanged this is effectively a step change in footroom requirement which is not present in the historic datasets.

347 It has also been demonstrated in the last year that there are several specific network outages that increase the high response holding requirement, which in turn increases the footroom requirement. A methodology that includes such network outages as drivers of footroom volume should increase the accuracy of the modelled target.

348 For the mid phase review points, the interaction of margin and footroom will also need to be considered. This is where both headroom and footroom requirements interact, and there is no alternative but to take actions on commercially inflexible units. This will likely require a review of the price forecasting element of the model.

Energy Model Incentive: Delivering Value to the consumer

349 The energy model, together with the proposed and potential enhancements set out above, aims to provide a robust and efficient cost target against which our performance can be measured, whilst also capturing potential changes in cost drivers over the next two years. To ensure the cost targets derived from the model remain appropriate against future uncertainty, we propose to review the models and associated methodologies after two years and then halfway through the RIIO-T1 period. This will ensure we continue to focus our strategies, decisions and actions on the elements that we can control or influence in order to deliver long-term value to consumers in the procurement of these services.

350 In order to minimise actual energy balancing costs in response to this incentive, we will we seek to innovate in the procurement of balancing services. In particular, we will focus on developing new contracting and trading strategies, new products, tools and technologies for the services we require. We will look to stimulate new markets and continue to encourage new providers into the provision of these services. We will explore the provision of services from new and existing generating plant, the growing renewable sector, from new interconnectors and in particular from the demand-side.

351 We are looking to enhance our assessment tools to better understand the services we required and how best these can be supplied. We will also seek to better communicate our requirements, both to build awareness of the services we require and to stimulate competition and innovation in the provision of these services.

352 New technology in homes and businesses focussed on energy conservation (e.g. Smart Appliances), the roll-out of Smart Metering and the anticipated growth in Electric Vehicles will all open up opportunities to source a wide variety of demand-side services to support the efficient operation of the NETS. Demand-side provision of constraint management, electricity storage, reserve, response and reactive power services are all feasible with the right technology, and innovation in these areas will be key to delivering value against the incentive scheme to the benefit of consumers.

BSIS: Constraint Modelling

Overview

353 This section sets out the principles of the constraint cost target model for BSIS over the RIIO-T1 period. We propose that the current boundary based model is employed for the 8 year framework which has been enhanced and expanded to more closely represent the NETS in order to provide a more accurate cost target. This decision to expand the current model is as a result of further work undertaken to develop a full nodal model within the Constraint model which proved too complex and onerous for application to the BSIS[36]. When proposing developments to the current model, the modelling principles set out in the 'BSIS Introduction' section and the review of model inputs in the 'Ex ante or Ex post Treatment of Inputs' section are considered.

354 This section comprises a high level overview of the amendments we are making to the model for the RIIO-T1 period following a review of the current model. Further details regarding performance of the current model and the rationale for enhancements can be found in Appendix B to this document.

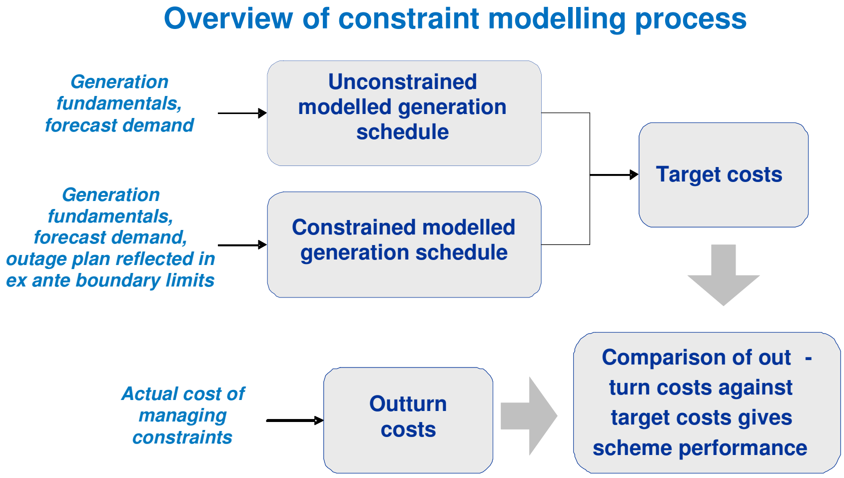
Background to the Constraint Model

355 Following Phase 1 of the SO Review, National Grid undertook a procurement exercise for a constraint cost forecasting model. As a result of this competitive tender process the Constraint model, an 'off-the-shelf' model, was selected as the candidate that best met the immediate and longer term requirements for constraint cost forecasting.

356 The Constraint model solution employed for the current scheme is known as the 'interim solution', which uses a simplified, boundary-based model to represent the transmission network. In addition to replacing our current suite of in-house constraint models that were used to calculate a constraints cost target prior to April 2011, the Constraint model also enables the modelling of generation despatch decisions using plant characteristics and market fundamentals. The boundary-based approach to the model is intended to represent the transmission network as a series of zones corresponding to existing and potential future constraint boundaries. The Constraint model is capable of modelling generation running using an economic merit order despatch model. It applies that generation running to both unconstrained and constrained network representations, so that a modelled level of constraint costs can be determined.

357 The high level principles applied when modelling constraints costs to develop a target that we are incentivised to outperform is as shown in the figure below:

[36] The reasons for ceasing work to develop a full nodal model within the Constraint model is set out in more detail in Appendix B to this plan.



358 The generation fundamentals model is used to generate a schedule of plant running to meet demand. The output of this schedule will be 'unconstrained' – i.e. it will assume infinite transmission capacity. The model is then re-run with a boundary model applied, which will represent the ability of the transmission network to transfer power between pre-defined zones. The boundary capabilities of each zone will be established to represent the transmission outage plan for the period covered by the scheme. Where a boundary's capability is exceeded, resulting constraints are resolved by re-scheduling plant using ex post offer/bid prices, to give an overall 'constrained' schedule of plant running to meet demand.

359 The difference in cost between the unconstrained and constrained model runs will give the modelled 'target' costs[37] against which out-turn costs will be compared to determine our performance under the incentive.

360 The use of the software model for constraints modelling is based on the application of optimisation techniques aimed at minimising total costs. The current model is described in more detail in the Constraints Modelling Methodology[38] which was agreed prior to the start of the current scheme.

Proposed Modelling Approach

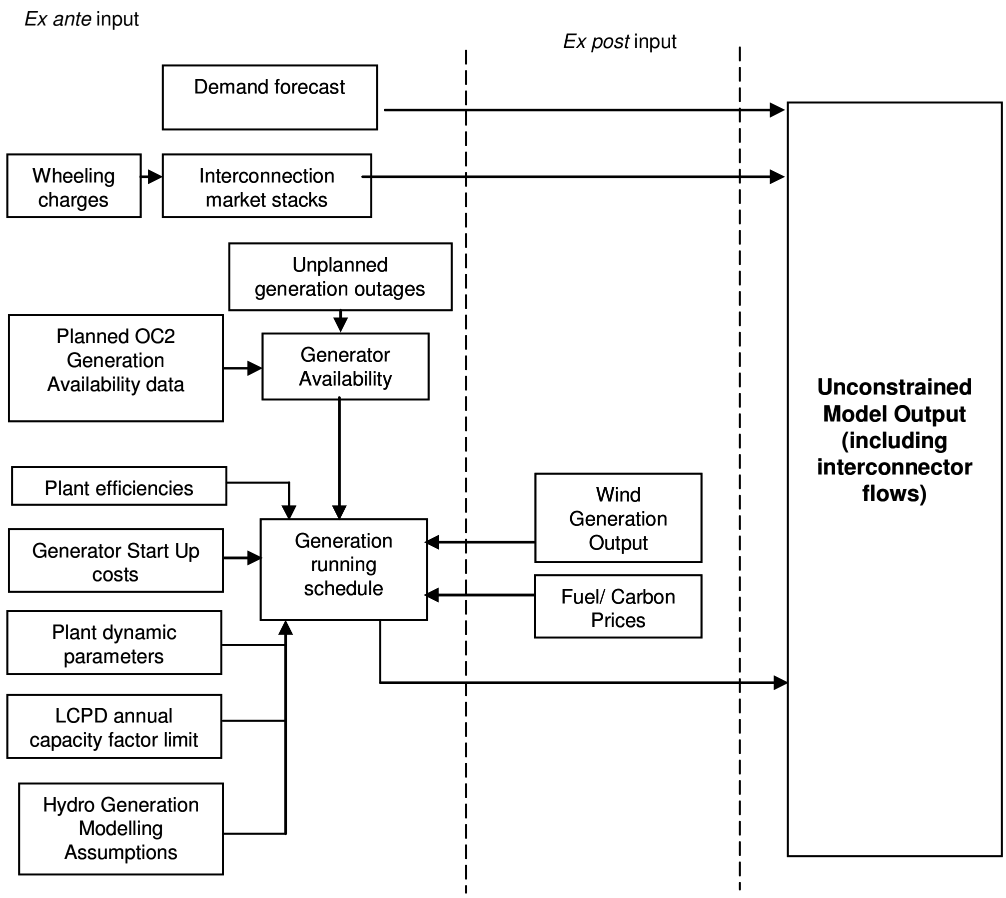
361 Having taken the decision to cease development of the full nodal model, we have looked to enhance the current Constraint model solution such that it more accurately represents constraints on the transmission system that we operate. This section firstly sets out the challenges we have identified in the Constraint model with regard to the unconstrained run of the model and any changes made to inputs accordingly. We then set out the proposed modifications to the constrained model run and how these will improve accuracy of the modelled target cost of constraints for the RIIO-T1 period.

[37] The modelled cost target is also subject to a discount factor of 41%.
[38] This methodology can be found on our website at: http://www.nationalgrid.com/NR/rdonlyres/32C1D8DC-D7AB-4C8B-950C-FBBB28A3975B/47900/Constraints_Modelling_Methodology_Issue1_18July2011_Final.pdf

Determining Generation Output

362 The first run of the Constraint model comprises a simulation of market behaviour whereby, assuming an efficient market, the self-despatched position of generators, in order to meet forecast demand, is defined by minimising the total operating costs (mainly fuel and start up costs), subject to a number of constraints on plant dynamics such as minimum run time, run up rates, run down rates etc. The diagram below illustrates this initial run of the model which will determine an unconstrained generation output. The diagram also shows which inputs to this model run are currently ex ante and which are ex post.

Unconstrained Output Model



363 The above unconstrained run of the model will not change fundamentally for the RIIO-T1 period in that a generation schedule will continue to be produced to meet a forecast demand. However, as set out in the earlier section ('Ex ante or Ex post Treatment of Inputs'), we have reassessed a number of ex ante inputs such that they are proposed to be treated as ex post from April 2013. The following section below sets out which of those inputs, relevant to the constraints model, will change from ex ante to ex post and describe how and when all datasets will be input to the model in the unconstrained run.

364 In principle, the unconstrained model should reflect (and model) the self-despatched generation running patterns observed in reality at gate closure on

the NETS. If this is the case, wind fall gains and losses associated with inaccuracy in this model run are reduced and the incentive is further focused on the NETSO minimising rescheduling costs to secure the system in areas that are under our control and influence. Any model is only as good as the quality of the data that is input to the model and therefore it is critical that those inputs are as accurate as possible over an 8 year incentive framework.

Inputs and Sources of Data to the Unconstrained Run

365 The inputs relevant to the unconstrained run of the constraint model that have been reassessed in the 'Ex ante or Ex post Treatment of Inputs' section and proposed to be changed from ex ante to ex post treatment are:

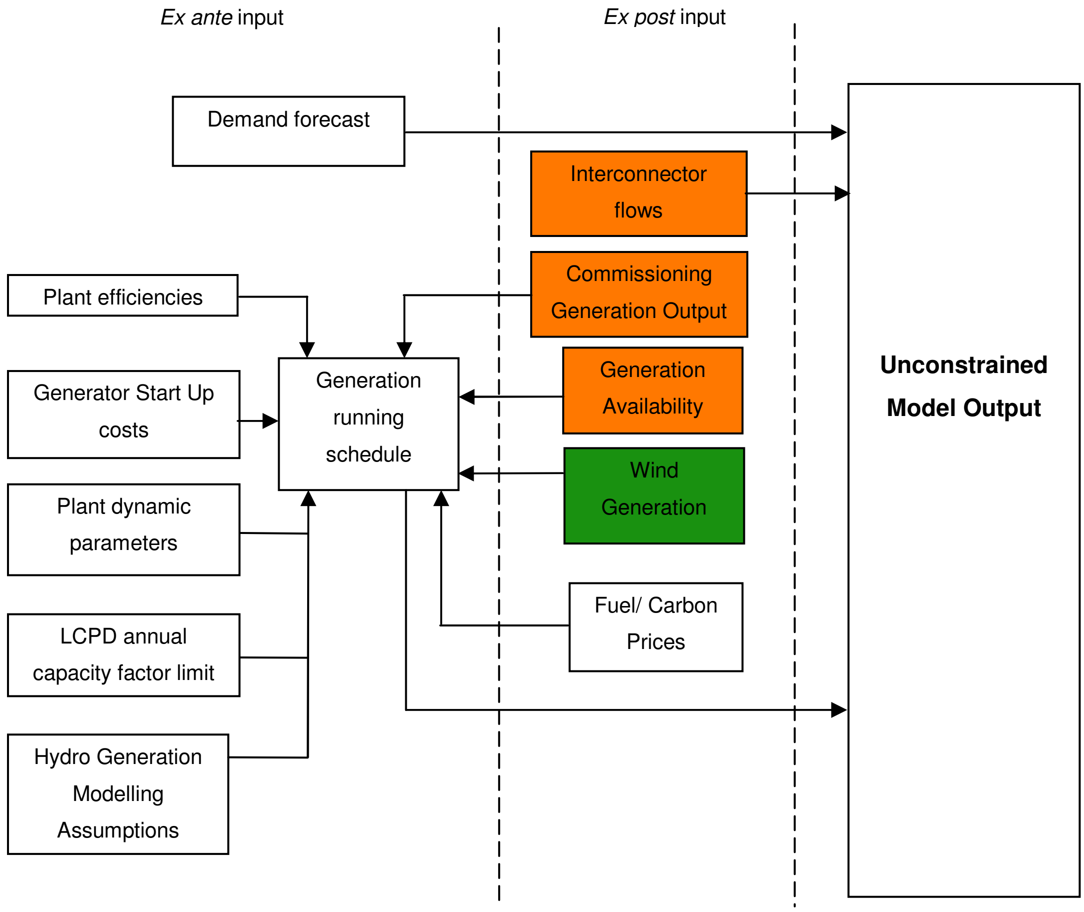
(a) Generation availability;

(b) Generation running – Commissioning Plant; and

(c) Interconnector availability and flows.

366 The reassessment of the above inputs are shown in the amended unconstrained run diagram below where the boxes highlighted in orange are the inputs proposed to be moved from an ex ante input to an ex post input. The green box indicates that whilst there is no intention to amend the already ex post treatment of the input, we propose to enhance how the dataset is determined. This is discussed further below.

Review of Inputs to the Unconstrained Run



Generation Availability

367 As set out previously in this document, the current model input for generation availability is ex ante year-ahead OC2 data submitted by generating companies in respect of their plant. We highlighted that due to the volatility in outage placement and scheduling within year, and the limited degree to which we can contract with generation at efficient prices to change their outages, the extent to which we can forecast or control generation availability is low. Similarly, with regard to unplanned outages of generation, we have low ability to control and no ability to forecast when these might occur.

368 Therefore, it has been proposed that generation availability is treated as ex post in the unconstrained run of the Constraint model where actual outturn MEL data is employed as the source data. This will be taken for each BM Unit for each settlement period and input to the model on a monthly basis in line with other ex post inputs. The source of this data will be the National grid Economic Data warehouse (NED), a system that stores and aggregates operational and half-hourly Settlement Data.

Generation Running – Commissioning Plant

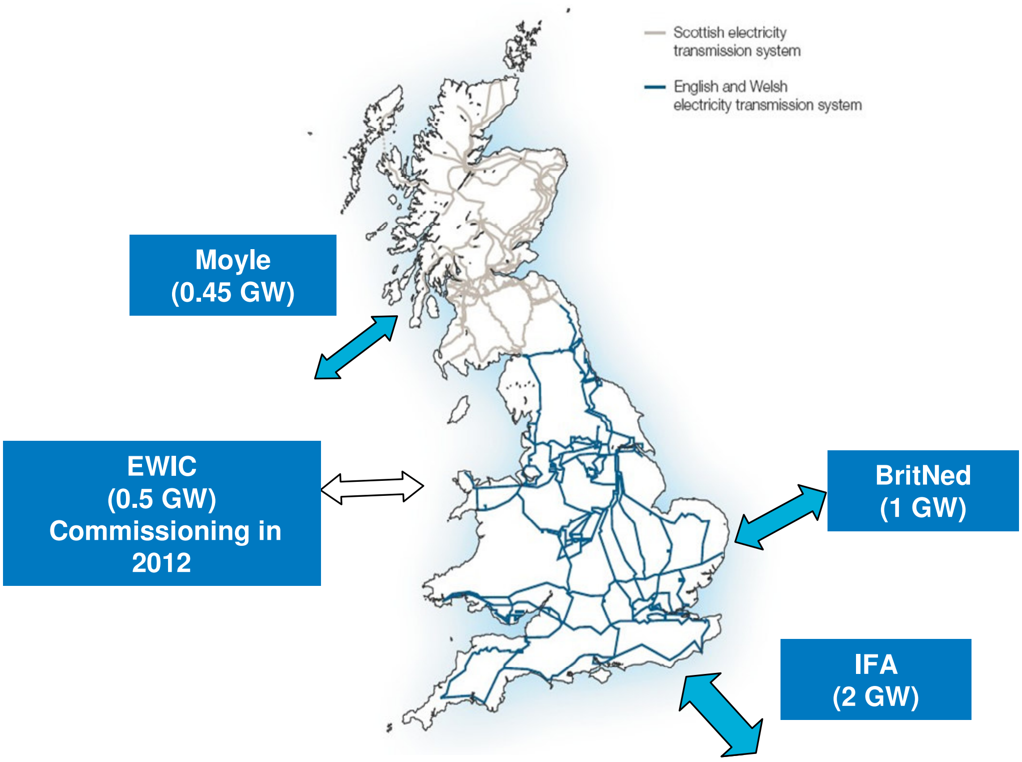
369 It was proposed that commissioning generating plant be treated as ex post rather than ex ante (as now) within the unconstrained run of the model because operating patterns of plant under testing programmes can differ greatly from generating profiles that would be determined by the market. Hence ex post treatment of generation output for a limited period would more accurately reflect how we as NETSO treat commissioning plant in operating the system and reduce scope for windfall gains and losses associated with constraint costs.

370 In practice, therefore, the actual outturn generation output of each commissioning BM Unit over the RIIO-T1 period will be input to the model on a monthly basis up to a maximum period of 6 months following initial operation of the plant in question. This represents an average timescale experienced through recently commissioned plant.

Interconnector Availability and Flows

371 The volume of interconnection to other non-GB markets is set to increase, with a fourth interconnector commissioning to southern Ireland during 2012/13 (as highlighted in the graphic below). Interconnector flows can have a considerable impact on the costs of system operation (e.g. the extent to which the Moyle interconnector is exporting to Northern Ireland will impact on the constraint volumes in Scotland and therefore the costs of resolving those constraints). The interconnectors are also a tool that we can use (post gate closure) to manage the system.

Interconnector Capacity Growth



372 The modelled target cost of constraints is therefore sensitive to interconnector flows and availability over which (pre-gate closure) we have very limited control. Currently, due to the simplistic way in which interconnectors are modelled within the Constraint model[39], we have witnessed inaccuracies in the way that interconnector flows are modelled for the current scheme i.e. making the assumption that an interconnector is exporting when it is importing in reality. This increases the scope for windfall gains and losses to the consumer, particularly over a longer incentive timeframe.

373 Modelling of European markets is complex and as it is markets that determine the pre-gate interconnector position, we feel that the modelling of Interconnectors should reflect this complexity. Implementation of the Third Package[40] capacity allocation rules will shortly mean that we, as NETSO, have no influence over pre-gate interconnector flows. Furthermore, through the adoption of the EU target models in respect of increased market coupling[41] and continuous trading on interconnectors, it will remove our ability to trade directly with interconnector users for firm price or volume. Therefore, as set out in the previous section, we are proposing that interconnector flows be treated as ex post in the model with actual flow notifications as at gate closure being input to the model on a monthly basis.

Other Ex post Inputs to the Unconstrained Run

374 Aside from the above three elements, now proposed to be ex post inputs to the unconstrained run rather than ex ante, the existing ex post inputs to the model will continue to be treated as ex post. These inputs are wind generation output and fuel/ carbon prices.

Wind Generation

375 For the current scheme wind generation output is input to the model on an ex post basis. We are not proposing to change this approach but rather to make improvements to the way in which wind generation is captured by the model such that it reflects the actual system conditions that we are required to operate more accurately.

376 Operational experience of the current model highlights two areas that require clarification and enhancement to ensure that the model is robust enough to encompass future sources of renewable energy e.g. solar photovoltaic (solar PV).

377 Firstly, the current scheme modelling approach is to calculate an average wind factor across GB for each half hour and use this to determine output of

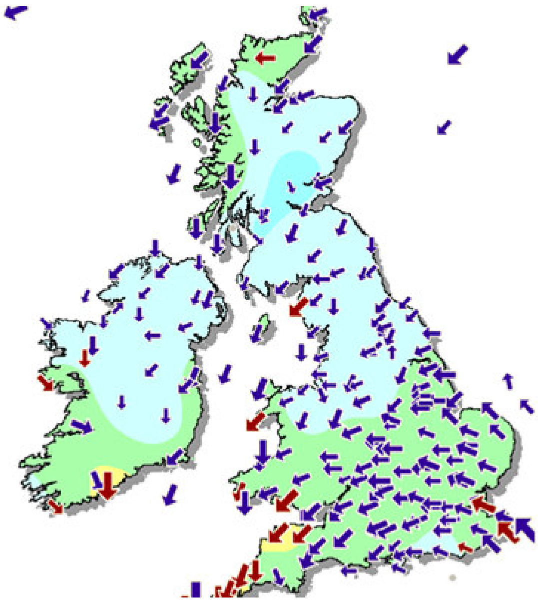
[39] Currently an ex ante wheeling charge is used in accordance with a simplified stack of generation which is reflective of the generation type mix within the non-GB market.

[40] Under EU Third Package, an interconnector user is obliged to release unused capacity to the market. As a result, where National Grid would once have been able to trade a counter party to a float position and sterilise the capacity with it, this can no longer be done. Instead a counterparty has to procure capacity in the desired direct post intra day capacity auctions

[41] Under market coupling, flows across interconnectors are determined through an auction across multiple markets. A clearing price is derived and flow determined by price differential alone, with currently limited opportunity to change flows intra-day. Also as volume is allocated through an auction it is not possible for the SO to trade specific and firm volume or price.

every wind farm in GB. For the wind pattern shown in the diagram below it can be seen that wind speeds are not uniform across the whole of GB. Using an average GB figure in this instance underestimates wind output in the south of England and overestimates output in Scotland.

Example of wind speeds across GB



378 This results in inaccurate modelling of the wind across all of GB which therefore has an impact on constraint costs forecast by the model. This can therefore also lead to wind fall gains or losses to the consumer.

379 Over the 8 year RIIO-T1 period, the potential output from large offshore wind farms will have a considerable influence on power flows on the NETS and the constraint volumes that may be generated as a result. It is therefore proposed to improve the current methodology from the calculation of an average GB load factor to a more regional resolution. For new renewable sources such as solar PV, we would adopt the same modelling principles as for wind if appropriate.

380 The second area of development from the current model is related to the modelling of embedded or "invisible" renewable generation output. The current methodology allows us to model the output of these generators but it is not explicit within the methodology as to what the source of this data should be. It is also unclear as to how to accommodate other renewable sources of generation as they become significant over the 8 year framework.

381 It is proposed that the source for this data be clarified for the start of the RIIO-T1 period which sets out exactly how we can use other auditable sources such as Ofgem's Feed-in-Tariff (FiT) Register. Thus the model will be able to accommodate future embedded renewable generation growth more accurately for the scheme duration.

Fuel/ Carbon Price

382 Wholesale fuel spot prices are currently input to the model on an ex post basis in order to derive the Short Run Marginal Cost (SRMC) for each generation unit based on the primary fuel type for that generator. A carbon price is similarly employed in the model to fully reflect the cost of generation which is also an ex post input. The inputs for these prices are obtained from the sources listed in the table below. For the RIIO-T1 BSIS, it is not proposed that these inputs and sources are changed from the current methodology.

Description of model input prices for fuel and carbon

Input	Source
Gas price Daily gas price in £/GJ	Bloomberg- Day Ahead[42]
Spot price at NBP	Coal price Weekly coal price in £/GJ
Bloomberg – Generic CIF	ARA Coal forward price
Carbon	price Annual carbon price in £/kg

383 The remaining inputs to the unconstrained run as set out below which are currently, and are proposed to remain, ex ante inputs to the model.

Hydro Generation Running Assumptions

384 Hydro generation behaviour is currently modelled on an ex ante basis within the Constraint model and this is not proposed to be changed for the RIIO-T1 period. However, the current modelling of this type of generation has resulted in an observed difference between actual and modelled output.

385 In the current scheme, it has been discovered that the BM modelled cost of pumped storage was not accurately captured during periods where the physical notification (PN) of pumped storage units was negative i.e. reflecting a pumping mode of operation. The software did not recognise that bids and offers can be associated with this mode of operation. The result of this was that those actions attributed to pump storage BMUs within the model to alleviate constraints were not reflected in the total cost.

386 We have therefore looked to enhance this input to the model by asking the software developer, [text deleted], to incorporate the additional functionality required. A software update has been made such that it incorporates bid and offer prices against negative PN operating profiles.

Demand forecast

387 We will continue to forecast demand on an ex ante basis throughout the RIIO-T1 incentive period via our well established internal processes. However, for the current scheme, a demand forecast was undertaken prior to the start of the scheme for the whole scheme duration i.e. a 2 year forecast was derived. During the RIIO-T1 period it is anticipated that we will be moving from a relatively predictable demand base to one that includes a significant level of

[42] The Bloomberg indices used as source data are NBPGDAHD, MSCMUSDT, ICEDEUA and EUCRBRDT. The Bloomberg exchange rates used to convert the prices into GBP are GBPUSDBGN and GBPEURBGN.

renewable generation with more variable output and demand that will become increasingly flexible, smart and price sensitive.

388 In order to account for this potential increase in volatility, we therefore propose that demand be forecast immediately prior to each incentive year within the 8 year framework for a rolling one year period. This will allow us to take into account the latest national econometric and historic data whilst maintaining the incentive to forecast annual demand as accurately as possible. The forecast will be conducted at a GB level and apportioned to grid supply points based on engineering judgement and experience.

Plant Efficiencies

389 For each individual BMU an ex ante heat rate or unit efficiency is applied to the wholesale fuel price, thus deriving a SRMC for each BMU. BMU heat rates are based on historical generation of each BMU and are categorised by plant type in the Constraint model. It is not proposed that these plant efficiencies be changed for the RIIO-T1 BSIS, however, as observed generator running regimes change throughout the scheme duration, we propose an annual mechanism by which these factors may be amended to more accurately reflect generation scheduled via the unconstrained run of the model. This input review process is set out in the 'Annual Model Review' section.

Start Up Costs

390 Start up costs are relevant information to the extent that they indicate the likelihood of certain generators to two-shift (desynchronise between two runs, typically overnight). These will continue to be a fixed ex ante input to the unconstrained run of the Constraint model and calculated in a similar way to efficiency factors. As set out above, these costs may need to be reviewed and adjusted throughout the scheme in order to ensure that the unconstrained run is modelled as accurately as possible. Any adjustments will be made via an annual, transparent model review process.

Plant Dynamic Parameters

391 Plant dynamic parameters for existing units will continue to be obtained (ex ante) from historical submissions in the BM which are available via the Balancing Mechanism Reporting System (BMRS) for the RIIO-T1 period. The types of parameters employed within the model will not differ from those currently used[43].

Treatment of Large Combustion Plant Directive (LCPD) opted out plant

392 In order to capture the behavioural effect that LCPD has on certain generating units, the model currently applies an annual capacity factor limit on those units which have opted out of the directive. The factor, calculated at 35% and based on observations since the directive came into effect, will therefore remain an ex ante input to the model. However, given that LCPD opted out

[43] The dynamic parameters used in the model are: Maximum Export Limit (MEL), Stable Export Limit (SEL), Minimum Zero Time (MZT), Minimum Non Zero Time, Run Up Rates and Run Down Rates.

plant is required to close by 2015, this will no longer be required as an input to the model after that date.

Ongoing Review of Ex Ante Model Inputs

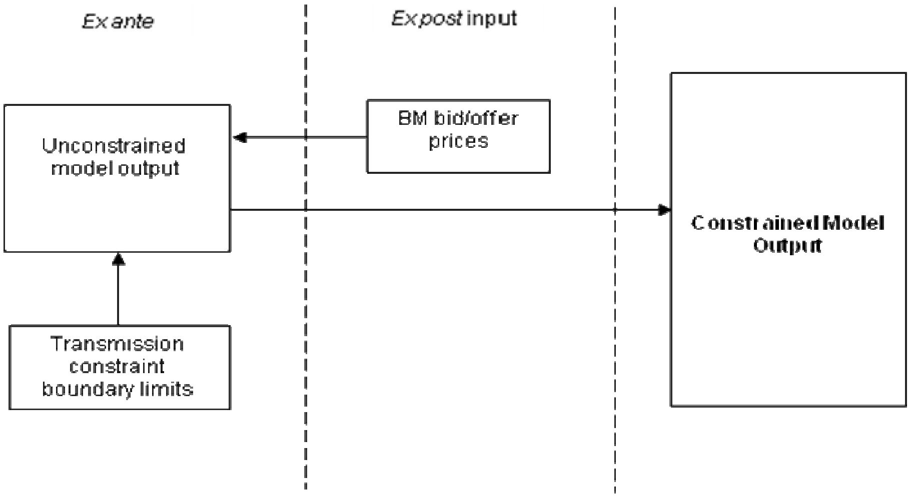
393 Whilst the majority of the original ex ante inputs to the unconstrained run of the Constraint model continue to be treated on an ex ante basis, we will need to ensure that those ex ante inputs (and therefore the modelled generation scheduled) continue to accurately reflect generator behaviour experienced by the NETSO on the system. Any inaccuracy within the unconstrained run will manifest itself through to the constrained run of the model, resulting in the relevant constraint boundary limits within Constraint model either being falsely breached or not breached accordingly. This, in turn, means that the modelled target cost, or the cost of resolving those constraints, will differ considerably from the actual costs that we incur but not because of any action that we may or may not have taken i.e. the possibility of windfall gains or losses is increased.

394 We therefore propose that all inputs, and the models themselves, are reviewed periodically throughout the scheme which will reduce the risk associated with a longer term incentive framework and scope for modelling inaccuracy. We set out this process, along with the types of amendments that may need to be implemented, in the ‘Annual Model Review’ section of this submission.

Determining Transmission Network Capability

395 As described above, the unconstrained run of the constraint model output emulates a generation schedule, and interconnector flows, to meet a forecast system demand. The second run of the model includes transmission system constraints where the model is re-run to determine a constrained generation schedule. The diagram below illustrates the constrained model along with which inputs are currently ex ante and which are ex post. These are not proposed to be changed for the model for the RIIO-T1 incentive period although we propose enhancements to those inputs so that the incentive on us remains focussed on those areas that we can control. These enhancements are discussed further below.

Constrained Model Run



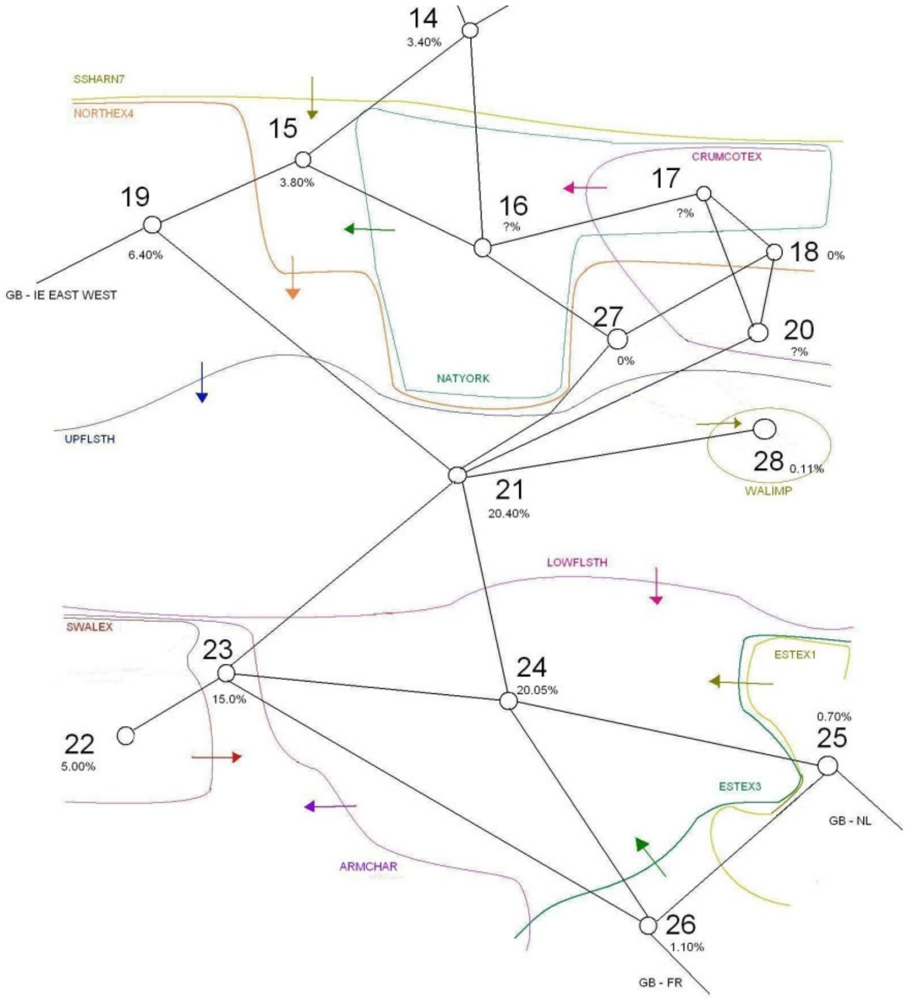
396 This second run of the model factors in the limitations of the NETS, where the difference between the two runs represents the model's assessment of the required volume and associated cost of constraint management activities. The current model is a zonal boundary model, consisting of a number of nodes, connected by single lines across which maximum boundary transfers are prescribed.

397 Generation and demand is attributed to each zone and nominal boundary flows are derived thereof. Where a boundary's capability is exceeded following output from the first model run, resulting constraints are resolved by re-scheduling plant using actual ex post BM bid/offer prices. This provides an overall 'constrained' schedule of plant running to meet demand and therefore a modelled target costs against which our actual incurred costs are compared to determine performance under the incentive.

Required input data to the constrained model

398 An example of the current model for England and Wales is shown in the diagram below:

England and Wales Transmission System boundaries within the Constraint model



399 There are currently approximately 33 nodes and 16 boundaries to model the whole NETS and limits for the boundaries were calculated on an ex ante basis for the 2 year scheme by National Grid. However, operational experience of the current constraints model during the current scheme has highlighted areas

for further development due to the simplicity of its approach. Examples of such issues include:

(a) The simplistic modelling of the network in the North West of Scotland results in constraint boundaries that are active which cannot be accurately modelled taking into account the correct location of generators. The result has been that the Constraint model has been able to use relatively cheaper pumped storage generation rather than curtail more expensive wind to resolve those constraints which has not been a feasible operational solution; and

(b) Throughout the last year, over night voltage constraints have been active and required generation to be constrained on for dynamic voltage support which was a new issue experienced on the system during the current scheme.

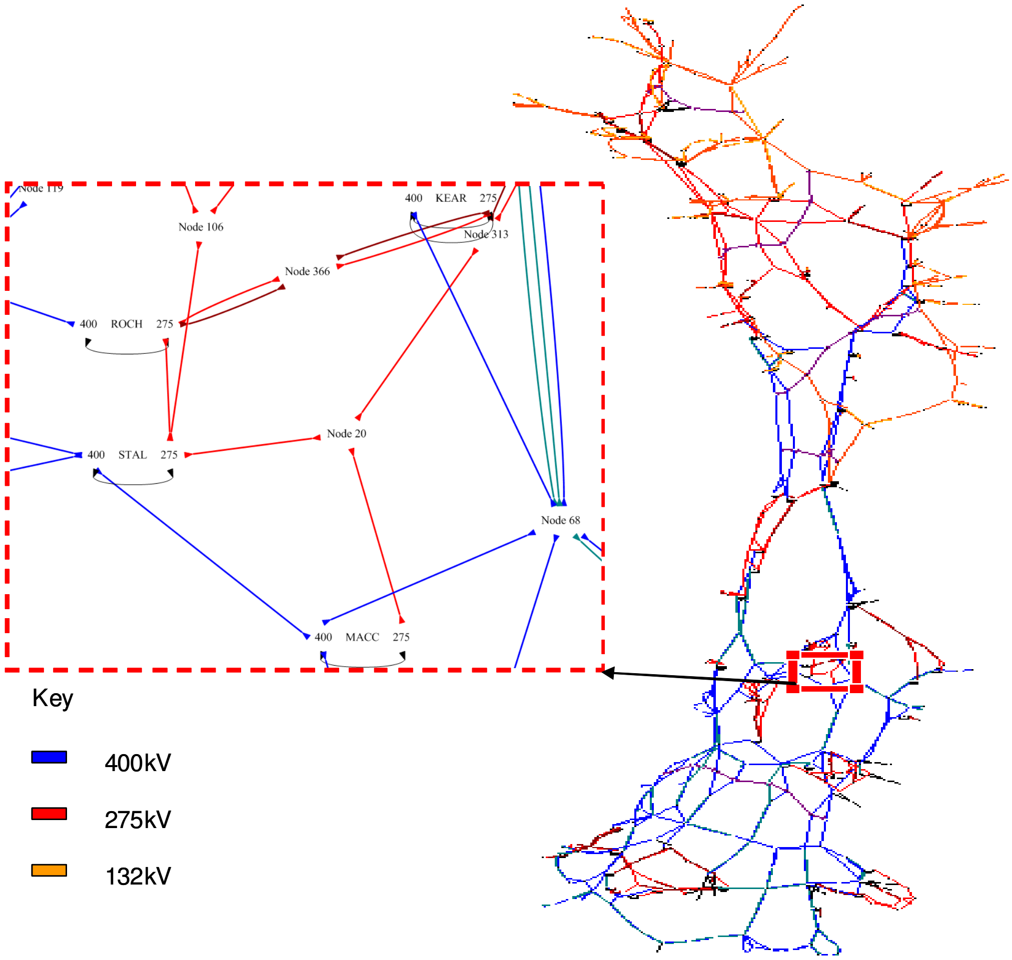
400 In the absence of a full nodal model, not pursued due to reasons described in Appendix B to this plan, and in order to address the issues experienced to date, the proposed constraints model for the RIIO-T1 period is a substantially expanded zonal model in the Constraint model. This will mirror the current BSIS model framework, albeit with the inclusion of significant additional detail in order to more accurately represent the constraints that we experience on the system and are required to resolve at cost.

401 The model will therefore be expanded to circa 621 nodes and 130 boundary limits[44] compared to the 33 nodes and 16 boundaries of the current scheme model. Although this is still not a complete network model with impedances and line ratings, and hence will not effectively model all outage combinations that can exist in the future, we believe that it will be a significantly improved model to the current approach.

402 An example of the model is shown below which, due to the additional nodes and boundaries, shows only a small magnified area of the modelled network:

Example of expanded nodes and boundaries within the Constraint model

[44] This is the anticipated number of nodes and boundaries within the enhanced model at time of writing which might be subject to change prior to April 2013.



403 The new model will incorporate the substations and lines which comprise the Main Interconnected Transmission System (MITS). The substations will be translated to nodes and will generally reflect a "solid" or electrically meshed configuration, unless the substation or node always runs with an electrical split.

404 The boundary limits will therefore reflect the impact of transmission outages, together with stability and voltage considerations. As such, it will only be necessary to identify the modelled loads on the MITS, so allowing the model to identify the necessary action required to ensure boundary flows do not breach the prescribed limits. However the retention of NASAP[45] coded line data will allow for the accurate definition of boundaries and thus define the nodal relationship more accurately. This will be important for the future inclusion of new boundary limits during the RIIO-T1 period as the NETS develops which is something that is not possible with the current scheme the Constraint model.

405 Finally, the model will include all of the lines/cables on the MITS and will be detailed by NASAP code and connected to all relevant the nodes. This will

[45] NASAP codes are the identification code for each piece of transmission equipment.

allow for the accurate capture of boundaries in respect of which line flows will be monitored or limited against a relevant boundary. It will also allow for a more accurate audit capability in respect of the assignation of assets to active boundaries.

Sources of input data to the constrained model

Boundaries to be modelled

406 As set out above, the boundary limits will reflect the impact of transmission outages, together with stability and voltage considerations. We have selected the location and number of boundaries based on the most common and most likely future bottlenecks in the system over the RIIO-T1 period, according to the operational experience of Power System Engineers.

407 To ensure the longevity of the model, it will be necessary to review these boundaries on a periodic basis in order to ensure that the constraints represented by the model reflect the capability of the actual network, including any reinforcements. This is so that the modelled target cost is also as realistic as possible thereby reducing scope for windfall gains or losses throughout the scheme period. It is therefore proposed that boundaries be reviewed annually via the model review process such that if any new boundaries are required, they may be reflected in the model for the following year (see later section entitled 'Annual Model Review').

408 Boundaries that differ from those proposed in the model prior to the start of the RIIO-T1 period may materialise over the course of the incentive framework for a number of reasons. For example, whilst we can plan in the boundaries that are associated with the RIIO-T1 TO plans (e.g. connection of the western bootstrap in 2015/16), there may be instances where additional boundaries not envisaged at the time become an operational issue. In addition, the unexpected closure of generation may result in constraints that were not apparent when the plant in question was available and running.

Boundary limits during outage conditions

409 Two year ex ante boundary limits during outage conditions, for the current scheme, were calculated through the development of offline power system studies. For each boundary, a subset of the outages planned to take place throughout the outage year were selected. The selection process was based on historic data and the operational experience of power system engineers, and represented the most significant outages in relation to their impact on boundary transfer capabilities. Less significant outages planned during the outage year were assumed to 'hide' behind those selected in relation to their impact on boundary transfer capabilities.

410 The offline power system studies were used to calculate the maximum power flow that can be accommodated across a particular boundary. For each boundary, multiple contingencies (circuit trips) were run to establish the most onerous fault conditions. For the most onerous fault conditions, the maximum power flow that can be achieved across the boundary has been calculated according to NETSQSS requirements.

411 Whilst we continue to believe that planned transmission outages should be treated as an ex ante input to constraints model, we are concerned that the dynamic nature of transmission outages within year could lead to the possibility of windfall gains or losses if the variability of the plan is not sufficiently represented in the ex ante dataset. This is of particular importance during the RIIO-T1 period where TO capital plans comprise extensive programmes of investment to accommodate the expected growth in low-carbon generation. The extent of the work to be undertaken will result in increased within year requests from the TOs such that these programmes can be accommodated and construction works delivered on time.

412 During the current scheme, there have been instances where, for example, outage overruns and short notice change requests to outages have resulted in significant additional cost being incurred by the NETSO. In theory, the NETSO can recall or even reject outage requests that were not planned in at the year ahead stage and are forecast to result in high constraint costs. However, this would not be conducive to the overall low carbon economy agenda or beneficial to end consumers.

413 To illustrate the volatility of a 1 year outage plan year, for 2011/12, only one third of the total outage volume (outage days) was planned in at the year ahead stage in the Final Outage Plan (FOP). This means that the remaining two thirds of the outage volume was requested and booked into the plan within year. This degree of change to the outage programme, having determined boundary limits at the year ahead stage for the purposes of determining the constraints incentive cost target, can result in actual constraint volumes that we experience being quite different from those determined by the ex ante dataset. The impact of any divergence between the actual and modelled constraint volumes has an impact on the accuracy of the modelled cost target.

414 Furthermore, although there is a mechanism by which the NETSO can request that the (Scottish) TOs make changes to outages[46] within year, in practice the majority of changes made to the plan are TO driven.

415 Thus there is a balance to be struck in terms of:

(a) Accommodating the considerable changes that invariably occur in outage placements within each incentive year;

(b) Ensuring that the system can be secured given these outage requests;

(c) Incentivising the NETSO to minimise operating costs and to work with the TOs to optimise outage placement; and

(d) Ensuring that the Constraint model has the correct active boundary constraints modelled to determine an appropriate constraint cost target.

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[46] This mechanism is the Outage Change Cost Allowance process is set out in the National Grid Transmission licence (Special Condition AA5A) and provides a cost allowance for the NETSO to compensate the Scottish TOs for reasonably incurred costs associated with National Grid requested outage changes.

416 We therefore propose to move away from a 2 year ahead ex ante approach to calculating and inputting boundary limits throughout the scheme period on a rolling 6 week basis ahead of real-time. These limits would reflect the network as provided by the TOs in delivering their plans but be exclusive of any SO inspired actions taken to provide incremental capacity across any given boundary, creating an equivalent to a TO 'baseline'. This would include all planned outages secured against a forecast generation and demand background at that point in time. This process is further explained below.

Boundary Calculation Process

417 The process for calculating the Constraint model constraint boundary limits on a 6 week ahead basis is proposed as follows.

418 The calculation will be based on load flow analysis carried out against a background of the planned outages for the 6 week time period under consideration. A demand forecast for the period will be determined via the same internal National Grid process as the year ahead forecast (as required by the unconstrained run of the Constraint model) and a forecast generation pattern will be determined from the output of the unconstrained run of the Constraint model.

419 Four types of constraint: Voltage, Stability, Thermal and Fault Level, will be calculated. Those actions which are considered as NETSO optimisation actions will not be incorporated into the calculation. This is so that any action that we take during the 6 week timescale, to reduce costs can be compared to the modelled TO baseline to determine whether we have created value in undertaking those actions.

420 Scenario analysis will be undertaken to derive import and export constraints across the system, considering at least the minimum and maximum demand periods of each day. For those constraints which depend upon a significant volume of wind or interconnector capacity the full variance of the range within the groups will be considered. To ensure the system is modelled holistically and account for variation in modelled generation patterns it expected that whilst not all constraints will be active at any one time, they will all be calculated and entered into the Constraint model.

Process Reporting

421 In order to maintain transparency around this process of calculating boundary limit inputs to the model on a rolling 6 week basis, we propose to employ the current (monthly) reporting meetings with Ofgem. In these meetings we will set out how the outage plan has evolved from the year ahead FOP and the reasons for those changes e.g. addition of TO requested maintenance outages. We will set out how those outages have been transposed to boundary limits for the Constraint model and where the significant variances arise from the previous calculation processes.

Assessment of the 6 week Boundary Calculation Approach

422 The benefits of this approach are that it focuses the incentive on us to undertake actions for the provision of incremental boundary capacity. Given

the extent of change to the outage plan, even from the year ahead stage, this solution presents a more accurate input to the Constraint model. Thus it provides a more accurate reflection of the network that we are required to manage up to real time and thus a more focussed demonstration of where we have been able to reduce costs for the benefit of consumers.

423 Further details of the types of actions we can take to add value and reduce costs through this incentive approach are discussed at the end of this section.

424 Whilst the boundary limits are calculated by National Grid, and not independently by the model itself, we consider that the process set out above presents a robust, auditable and repeatable methodology suitable for a longer term incentive framework.

425 This approach does mean that any outage optimisation that we can achieve in the plan between the year ahead stage and the 6 week ahead stage is subject to a weaker incentive as this is not taken into account when calculating the limits from 6 weeks ahead of real time. However, as set out above, the scope for us to initiate changes to outages particularly during the RIIO-T1 period, where TO capital programmes are so extensive, will be significantly reduced. Furthermore, in the absence of a more certain view of generation availability and running (plus interconnector flows), the ability to optimise outages on the basis of constraints costs prior to the 6 week ahead timescale in limited. The year ahead planning process is largely concerned with securing the system for required outages with cost optimisation of those outages occurring much closer to real time.

426 We believe that this approach creates the optimum incentive on us to work collaboratively with the TOs to reduce constraint costs within areas that we can actively control and influence. We discuss the mechanisms and processes by which we will work together with the TOs further in the 'SO-TO Interaction' section of our plan.

427 Also, within the 'Aligning NETSO and TO constraint incentives' section we propose an approach to further align the incentive for both the Scottish TOs and the NETSO to reduce constraint costs to the end consumer.

Costing Constraints

428 For the current scheme, constraint costs are priced in the constrained run using ex post outturn BM price submissions. We carried out extensive analysis as part of the SO Review, prior to the current scheme, to identify whether it was possible to forecast BM price submissions on an ex ante basis to calculate the target cost of resolving constraints. The conclusions from this work[47] were that it was not possible to forecast BM prices with a sufficient level of accuracy for it to be appropriate to use them on an ex ante basis for an incentive scheme. As we have no control over the level of price

[47] The results from previous efforts to model BM prices are set out in the Constraints Addendum to the Initial Proposals for the current scheme – http://www.nationalgrid.com/NR/rdonlyres/FD7E0C91-4A12-4DDE-AC27-6B49685EF0A9/44512/Initial_Proposals_ConstraintsAddendum_Final.pdf

submissions it was agreed for the current scheme that BM prices would be input to the model as an ex post input.

429 At Ofgem's request, as part of the Supplementary Review we have undertaken further analysis to investigate whether there are additional explanatory variables with which to model BM prices on an ex ante basis. This analysis can be found in Appendix B to this plan.

430 On the basis of both previous analysis undertaken for the current scheme, together with the additional analysis carried out as part of the Supplementary Review, we do not believe that prices can be forecast with a satisfactory degree of accuracy. We therefore propose that prices continue to be input to the model on an ex post basis throughout the RIIO-T1 period.

Ex post BM prices – contracting restrictions

431 Having determined that BM prices be treated on an ex post basis for the current scheme, Ofgem expressed concern about the potential for National Grid to enter into constraint contracts that placed conditions on the BM prices that generators could submit (e.g. capped offer and collared bid prices). Such contracts had been used historically on occasion to create price certainty when managing constraint volumes in real time e.g. to manage the uncertainty of wind generation output associated with a system constraint.

432 Ofgem considered that to allow these types of fixed or indexed price contracts could result in National Grid effectively gaming the incentive to our benefit given that actual prices contracted or otherwise) submitted by generators in the BM are used to price the actions taken by the model to resolve the constrained run. As a result, Ofgem amended National Grid's licence with a condition that limits, for the duration of the current scheme, our ability to enter into any contract that places conditions on the prices at which a generator (or other market participant) will submit offers or bids in the BM in respect of any BM unit.

433 Given that we propose to maintain ex post BM prices as an input to the model, Ofgem's concern will continue to be an issue. Throughout the current scheme there have been instances where the opportunity to contract for BM price certainty to manage constraints in real time would have provided additional benefit and therefore reduced costs to the consumer. However, we have sought to overcome the licence restriction by entering into shorter lead time option contracts. These can be called upon at relatively short notice to deliver volume based solutions at fixed contract prices without influencing submitted BM prices in any way[48].

434 Option contracts therefore provide some degree of additional flexibility when managing certain types of constraints. However, there remains the risk that having called the contract off, the constraint volume for which that contract was acquired does not materialise. For example, if we enter into a contract

[48] Details of the constraint management contracts that we have agreed during the current scheme duration can be found on our website at:
http://www.nationalgrid.com/uk/Electricity/Balancing/services/systemsecurity/constraint_agree/Requirement/

where a generator requires three days notice to reduce its output to manage a constraint and we call upon that generator to reduce output in that timescale, there is a risk (for example) that the wind output forecast three days ahead does not materialise on the day. This scenario would result in a cost being incurred inefficiently whereas the ability to manage an uncertain constraint volume real time with the certainty of BM prices can be more efficient.

435 Whilst we believe that a licence restriction to rule out the use of BM price based constraint management contracts during the RIIO-T1 period is unnecessary we understand why it may be an area for regulatory concern. In the absence of an alternative method i.e. a suitable counterfactual rule whereby the BM price that would have been submitted by a particular BMU had it not entered into the price based contract with National Grid can be calculated, we understand that this restriction may remain in place. This is something that we will continue to review over the course of the RIIO-T1 period.

Constraints Discount Factor

436 Under the current BSIS scheme, the constraint cost target is derived as follows:

*Constraints target cost = model output * discount factor*
+ headroom replacement cost

437 The discount factor was intended to reflect the fact that the model will only use actions in the BM to resolve constraints, but in reality, some constraints can be resolved more economically via contracts and trading. The discount factor is currently set at 0.59 (reducing the modelled cost of constraints by 41%), and was intended to define an economic cost of constraints against which we are incentivised to outperform. This is significantly higher than the 26% figure recommended by Frontier Economics in April 2011 and in hindsight was set at an unrealistic level.

Issues with the current BSIS scheme

438 Constraint costs incurred during 2011/12 totalled £260m (excluding headroom replacement costs of £79.7m). We estimate that the equivalent BM cost of resolving constraints during 2011/12 would have amounted to £328m had it not been for our contract and trading activities during this period to resolve constraints more efficiently. As such, we delivered approximately £68m of savings against the equivalent BM cost of resolving constraints, equating to a 20.7% saving in 2011/12.

439 The current model used to determine constraint targets however identified a constraint cost target of £102m, representing only 31% of the equivalent BM cost of resolving constraints during 2011/12. This major underestimate was further discounted by 41% when setting a constraint target of £60.2m, which is compared to the outturn constraint cost of £260m (excluding headroom replacement), thus generating a significant loss of £50m under the existing BSIS scheme for constraints (although losses are capped at £50m over the two year period of the scheme). This is despite the savings we have

generated for customers through an extensive range of activities to minimise constraint costs.

440 This is not a sound basis for incentivisation, either for today or for the RIIO-T1 period. However, it was always recognised that the new modelling approach would need refinement in light of experience if it were to be considered suitable for longer term incentive schemes.

441 Based on perfect hindsight, rather than reduce the modelled constraint target by a factor of 41%, for target revenue to have matched actual costs, and assuming that the entire benefit of our contract savings was passed to consumers, the constraint cost target would need to be increased by a factor of 255%. It is clear that the 41% discount currently applied is not appropriate and has been one of the material factors that has served to undermine the effective operation of the current scheme.

442 We have identified a number of issues with the model and the associated methodology that, if corrected, would improve its forecasting ability. We propose to launch a consultation with the industry later this summer on how we might address these issues. These changes are currently estimated to increase the model output to £204m, representing 62% of the equivalent BM costs to resolving constraints during 2011/12. Application of the 41% discount factor would provide a target of £120m against the outturn of £260m, thus reducing the loss under the BSIS scheme to around £35m for constraints in 2011/12. While this is a modest improvement, clearly the ability of the model to accurately forecast the actual constraints we experience in operating the system should be taken into account when setting the incentive scheme target.

Modelling Constraint Volumes

443 Taken together, the target determined by the current model significantly underestimates the volume of constraints that will occur in reality. As described above, the current model only identified 31% of the equivalent BM costs of resolving the constraints during 2011/12, although this will increase to 62% if the changes we propose to make to the existing model to improve its accuracy for the current scheme are made.

444 In developing a new model for use over the RIIO-T1 period, we have proposed a number of enhancements that will further increase its accuracy. In particular, increasing the number of constraint boundaries, and treating interconnector flows/outages and generator availability as ex post inputs will significantly improve its forecasting ability.

445 However, the new model (and if fact any model) will still represent a simplification of the complex half-hourly process of operating the NETS, and cannot identify the full range of constraint conditions that will arise on the system. Despite the improvements we propose to the model, it will continue to underestimate the volume of constraints that will occur in reality. In particular, the model will not identify:

(a) Local constraints not captured by the boundaries included in the model;

(b) Boundaries that change as a result of particular outages;

(c) Short-term/temporal constraints arising from specific generator/demand scenarios occurring in real-time;

(d) The need to contract to reduce risk or create operating certainty (e.g. of plant availability) such that the system can be managed securely;

(e) Constraints that arise due to limitations in operating configuration (e.g. fault levels);

(f) Voltage and transient stability constraints which cannot be defined by a boundary in the model; and

(g) Unplanned system outages.

446 Furthermore, the model assumes perfect foresight in resolving constraints. In practice, decisions made in real time will not always reflect what in hindsight the model would determine the most optimal solution.

447 At best, it is estimated that the new model may only be capable of identifying 75% of equivalent BM costs, and this should be taken into account in setting the constraints incentive target. We therefore propose that the output of the new model is uplifted by factor of 1.33 to account for this constraint forecasting discrepancy for the first two year phase of the RIIO-T1 period. Clearly, with experience using the new model, we will understand its accuracy, and be able to adjust this uplift factor accordingly for the subsequent years of the scheme.

Constraint Contracts

448 We can use a range of tools to minimise the cost of constraints compared to rescheduling generation via the BM. These include contracts to curtail the output of generation behind export constraints (including generator intertrips), and contracts to run generation (or reduce demand) in areas where there is an import constraint.

449 These contracts incur costs, and we, on behalf of consumers, determine whether these costs will be lower than those we would otherwise incur in the BM over the duration of the contract. Any benefits achieved reflect the value-added by us in managing the system efficiently on behalf of consumers, whilst any additional costs reflect an inefficient contracting decision. In making decisions as to whether or not to contract, it is important that our incentives are aligned to those of consumers, such that the costs and benefits of these contracting decisions are shared appropriately.

450 As set out above, we estimate that we delivered approximately £68m in savings during 2011/12, by trading across interconnectors and contracting for constraint management services outside the BM. This equates to a saving of 20.8% against the equivalent BM cost of resolving constraints. However, there are a number of challenges that are likely to make this level of saving difficult to sustain going forward, including:

(a) The introduction of the Transmission Constraint Licence Condition (TCLC) is likely to see the scale of savings we can derive through contracts relative to the BM become more marginal, as prices of both converge towards the short-term marginal cost of providing constraint management services (or the value of ROCs for renewable plant);

(b) As contract prices become more marginal, the scope for entering into constraint contracts will reduce as the risk of such contracts turning out to be inefficient increases;

(c) We have received indications from generators seeking to terminate commercial intertrip agreements (which provide the most economic means of resolving constraints), over concerns that these may be deemed to be in breach of the TCLC. This implies that the scope for using contracts to reduce constraint costs in the future may be more limited;

(d) The level of achievable benefits is dominated by the use of commercial intertrip arrangements. However, the scope for using intertrips in a given area is limited by the maximum instantaneous loss the system is designed to withstand and pre-fault circuit ratings. For example, it would not be technically viable to intertrip all constrained generation north of the Cheviot export constraint. As such, opportunities for new intertrip schemes have a natural limit. With the volume of constraints expected to increase, the benefits achievable will therefore trend towards the more marginal savings that can be achieved through contracts to constrain generation behind export boundaries, rather than the benefits that can be achieved with commercial intertrip agreements;

(e) Future proposals for continuous trading on Interconnectors will remove the ability to solve constraints using Interconnector trades, as is currently undertaken;

(f) As conventional plant levels decline, the value of trading and contracting with these market participants will reduce. It is unclear if new entrants will offer similar benefits that has historically been observed; and

(g) Participants are increasingly demanding value, rather than cost for constraint management contracts, hence the savings that can be achieved through contracting will become more marginal compared to prices forecast in the BM.

451 We therefore propose that for the RIIO-T1 period, the target determined from the model should be used to represent the efficient level of costs against which our performance is judged. To the extent we can outperform this target the incentive scheme will ensure these benefits are shared with consumers according to the sharing factors of the scheme. Setting this target in this way will ensure that the value added by the NETSO in managing the cost of constraints on behalf of consumers is properly rewarded.

Calculating the Constraint Cost Target

452 Building on the approach detailed above, we propose that the constraint cost target is calculated as follows for the BSIS scheme under the first 2 years of the RIIO-T1 period:

*Constraints target cost = model output * Uplift Factor*
+ headroom replacement cost

Where $$Uplift\ Factor = \frac{1}{Model\ Accuracy} = \frac{1}{75\%} = 1.33$$

453 The Model Accuracy parameter, initially set to 75%, would be reviewed after the first two years of the scheme to assess the capability of the model to accurately identify actual constraint volumes.

Constraint Cost Incentive: Delivering value to the consumer

454 The cost of operating the network over the RIIO-T1 period will predominantly be driven by costs of managing transmission constraints. Following introduction of the Connect and Manage regime, the volume of constraints on the system will increase as wider transmission reinforcement works are delivered after the connection of generation. In addition, as more renewable generation is connected to the NETS, a higher number of constraint management actions will be required as power flows vary with renewable generation output.

455 The constraint cost target modelling approach set out above aims to reflect as closely as possible the underlying drivers of constraint costs, thereby focussing the incentive on those elements that we can reasonably control or influence as NETSO. We will be incentivised to make further use of smart tools and other innovative ways of operating the network ahead of wider capacity investment.

456 In order to minimise actual constraint costs against the modelled target, and thus earn a return from the scheme, we can seek to manage down the volume of, and/ or the price associated with, constraints. A balanced approach will be required if this is to be achieved between:

(a) Delivering the SO (internal) capabilities as set out in our March RIIO-T1 TO plan e.g. driving improvements to our generation and demand forecasting capabilities;

(b) Optimising the use of physical TO assets;

(c) Development of contractual and commercial solutions; and

457 The second two points from the above list are discussed further below.

Optimising use of the Transmission System

458 Over the RIIO-T1 period, the proposed constraints incentive encourages us to be innovative in the way that we operate the network and work with the TOs to optimise the use of existing assets. We are also incentivised to develop and agree mechanisms for network Users to provide actions post-fault to manage the impact of faults.

459 The actions that we can take to reduce constraints include:

(a) Transmission outage placement – request that TOs change or move outages in the short term;

(b) Substation reconfiguration – seeking innovative configurations for running substations to optimise system flows;

(c) Employ dynamic line ratings based on installation of circuit monitoring equipment;

(d) Enhanced/ short-term ratings - such that assets are able to transfer more power for a short period based on the thermal characteristics of the plant;

(e) Installation of bypasses;

(f) Thermal up-rating of circuits (hotwiring) – increasing the capacity of a circuit such that more power can be transferred across that circuit;

(g) Demand transfers and DNO reconfiguration – constraint actions may be avoided in some instances by transferring demand out of a group;

(h) Installation of smart technologies on the network such as commercial generator intertrips[49] and energy management systems;

(i) QB optimisation – tapping QBs to optimise flows on the system; and

(j) Reactive compensation optimisation – efficient use of generation, transmission assets and static compensation equipment to manage voltage constraints.

Ancillary Services and Trading Strategy

460 We are also incentivised to further develop ancillary services and contracting and trading strategies to facilitate competition and create more flexible tools with which to manage constraints on the system. One such area, as set out in the 'SO Innovation' section, is further development of wind trading options with wind farm providers which has proved to be an economic route to managing system constraints during the current scheme.

461 More generally, the development of operational commercial arrangements will ensure that, for example, the capabilities of new generation and demand side service providers can be best harnessed. We will need to ensure that the mechanisms through which these new types of providers can participate in our services are sufficiently flexible to remove barriers to entry.

462 In addition, we are incentivised to facilitate the market more generally by, for example, through information provision and industry Codes development. We will continue to engage with the industry participants on our experiences and challenges associated with operating the system through our Operational Forums in order to gain feedback and industry views.

[49] Commercial intertrips are those which are not associated with a generator Bilateral Connection Agreement condition.

463 As set out in the ‘SO Innovation’ section it will be critical therefore for us to innovate in the above areas over the 8 year incentive to deliver value to consumers through a reduction in constraint costs.

BSIS: Aligning NETSO and TO constraints incentives

Overview

464 This section sets out a proposal to create a stronger alignment between the NETSO and each TO in managing manage the cost of constraints on the relevant TO networks (including new TO networks that emerge during the RIIO-T1 period). It proposes to transfer a proportion of the incentive on managing the volume of constraints to those parties best able to manage those volumes (i.e. the relevant TOs) whilst maintaining the incentive on the NETSO to efficiently manage the cost of those constraints.

Background and Objectives

465 Over the RIIO-T1 period, significant quantities of renewable generation are expected to connect directly to the NETS, a large proportion of which will connect in Scotland and to other new Transmission Owner (TO) networks (e.g. new offshore networks). In England and Wales, the combined Transmission System Operator role of National Grid allows for the optimisation of decisions between our integrated TO and NETSO activities to minimise the overall cost of constraints to consumers. Aligning NETSO and TO incentives for England & Wales by aligning incentive scheme sharing factors, as proposed by Ofgem, will further promote such optimisation.

466 However, whilst we can minimise the cost of constraints on other TO networks, our ability to manage the volume of constraint costs is much more limited, particularly where these TOs have responsibility for planning, maintaining and operating their own networks. Although they have the incentive to build capacity to reduce network constraints in the longer-term, there is currently no financial incentive on these organisations to minimise the constraint costs they impose on customers through their construction and maintenance activities.

467 It would not therefore be appropriate for the NETSO to have the same incentive scheme sharing factors for managing constraints on these networks compared to our own. We have limited control over the level of transmission capacity made available on these networks and therefore on the volume of constraints this creates.

468 However, it may be appropriate to create a commercial incentive for these TOs to undertake their activities in such a way as to optimise the level of transmission capacity they make available on their networks, thus minimising the volume of constraints, whilst ensuring all necessary investment and maintenance work is delivered efficiently.

469 We note that the success of these commercial proposals to align incentives will be reliant on a design that takes full account of the different roles and responsibilities of the NETSO and the TOs and the information that is available to each party. We also recognise that the success of the arrangements may rely on the provision of additional information from us to the TOs.

470 In their responses to Ofgem's consultation on the SO Incentive Scheme from 2013, the majority of stakeholders were supportive of a greater interaction between the SO and the TOs and an appropriate incentive; as long as it was transparent and to the benefit of consumers.

"In electricity, where the TO and SO is not entirely under common ownership the relationship will be more complex. It will be important to ensure that costs are not simply passed between SO or TO for no overall benefit."
AEP's response to Ofgem's consultation on "System Operator incentive schemes from 2013"

Identifying the Constraint Cost Incentive for individual TOs

471 The constraint volume incentive in each TO area can be determined as the difference between the target and outturn cost of constraints as determined by the Constraint model for each TO area. This calculation assumes there are three TOs denoted as National Grid (NG), SHETL, and SPTL, but this approach could be expanded as the number of independent TOs increase. The model proposed also implicitly shares constraint costs on boundaries between the TO networks.

472 Constraint costs are determined using the Constraint model as follows:

TCC_{GB} Target Constraint Costs, which is the cost from a Constraint model run using ex-ante boundary capabilities to determine the overall target for GB constraint costs

MCC_{SPTL} The constraint costs of a Constraint model run as in the target model except using actual boundary capabilities in the SPTL region

MCC_{SHETL} The constraint costs from a Constraint model run as in the target model except using actual boundary capabilities in the SHETL region

MCC_{NG} The constraint costs of a Constraint model run as in the target model except using actual boundary capabilities in the NG region

MCC_{ALL} The constraint costs of a Constraint model run using actual boundary capabilities in all regions

473 In each case, the Constraint model is used in accordance with the constraint modelling approach (set out in the 'Constraints Modelling' section) and the ex-ante/ex-post methodology (set out in the 'Ex ante or Ex post Treatment of Inputs' section). Ex-ante boundary capabilities are determined in advance, reflecting the baseline network boundary capabilities planned to be made available by the relevant TO. Actual boundary capabilities are based on the network made available by the relevant TO in real time, including the provision of short-term ratings and other initiatives to provide incremental transmission capacity, but excluding incremental capacity achieved through NETSO contracts with generators.

474 The Constraint Cost Incentive for each TO area is then determined as follows:

$$CCINGET_T = (TCCGB - MCCNGET) x\ SOA$$

$$CCISPTL = (TCCGB - MCCSPTL) x\ SOA$$

$$CCISHETL = (TCCGB - MCCSHETL) x\ SOA$$

475 Where the scaling factor to ensure the individual constraint cost incentives equal to the total is calculated as follows:

$$SOA = \frac{TCC_{GB} - MCC_{ALL}}{(TCC_{GB} - MCC_{NG}) + (TCC_{GB} - MCC_{SPTL}) + (TCC_{GB} - MCC_{SHETL})}$$

476 These represent the different between the actual and target costs for resolving constraints in each TO area, as determined by the Constraint model. They will be positive if the TO provides incremental capacity across constrained boundaries in its region such that constraint costs are lower, and negative if capacity is more constrained such that constraint costs are higher.

Amending the BSIS Incentive Scheme

477 The BSIS incentive scheme would be amended as follows to reduce our exposure to the volume of transmission constraints in non-National Grid transmission areas. This arrangement recognises that we have limited influence over the availability of transmission capacity in other TO regions.

478 A residual (5%) exposure to the volume of constraints in other non-National Grid regions is proposed, to reflect the fact that the NETSO may have some residual scope to co-ordinate with the TOs in assisting to manage down constraint volumes in their regions (e.g. assisting with the development of outage plans and creating awareness of where constraint cost may arise and how they might be avoided).

$$\mathbf{IncPayExt = SF * [ITC - IBC]\ -\ (SF - 5\%) * [CCI_{SHETL} + CCI_{SPTL} + CCI_{other.....}]}$$

Where:

ITC Total Incentivised Target Cost for the Balancing Services Activity;

IBC Total Incentivised Balancing Costs; and

SF Incentive Scheme Sharing Factor.

479 Under this proposal, we would continue to be incentivised to minimise the total cost of transmission constraints, and be fully incentivised to manage the volume of constraints in across the National Grid system in England and Wales, optimising NETSO and TO decisions to deliver long-term value to consumers.

Constraint Incentives on non-National Grid TO Organisations

480 This approach allows the creation of a commercial incentive for TOs to minimise the volume of constraints on their networks in operational timescales. A contractual arrangement could be established between NETSO and the associated TO organisation which would allow an incentive payment as follows:

TO Incentive Payment = (SF - 5%) * $\mathbf{CCI_{TO}}$ {subject to caps/collars}

481 Under this arrangement, TOs would receive a benefit from innovative solutions to reduce the volume of constraints on their networks (e.g. the provisions of enhanced short-term ratings, live-line working, 2 shift/weekend working etc). They would conversely receive a penalty for an increased volume of constraints resulting from additional outages/overruns and fault outages.

482 Incentive payments would be paid to the TOs by National Grid in accordance with this calculation if CC_{ITO} is positive (i.e. incremental capacity is provided to reduce the volume of constraints), and incentive payments collected from the TOs if the calculation is negative. These would be recovered/ credited by National Grid via BSUoS charges, such that the overall cost of incentives would be no different to consumers for an equivalent outturn cost of constraints. Incentive payments to the TOs would need to be treated as excluded revenue under this proposal.

483 Importantly, under this proposal, the non-National Grid TOs would not be exposed to sub-optimal decisions by the NETSO in managing the cost of constraints, either using the BM or via constraint contracts. The non-NG TOs would be subject to the same incentive as National Grid to maximise the available level of transmission capacity made available to the NETSO in operational timescales.

484 The non-National Grid TOs would only be exposed under this arrangement if the actual boundary capability differed from the ex ante boundary capabilities established 6 weeks ahead of real time which is something that should be within their control.

485 We believe that this incentive mechanism would create a strong alignment between National Grid and the independent TOs to minimise the cost of constraints across the various TO networks. It would also avoid the need for complex contractual provisions between National Grid and TOs which would be difficult to manage, such as for moving outages etc.

486 The proposals set out here are designed to be an incentive to the TOs, such that these organisations would stand to benefit from their innovative actions that would minimise the overall impact on customers to constraints arising on their networks. They would also remove the need for the National Grid to contract with the TOs for changing outage patterns, provision of incremental capacity and the need to develop arrangements to manage outage overruns by the TOs, as there would be a direct incentive on these TOs to optimise their outage program and the capability of their networks to minimise constraint costs.

487 Clearly, this proposal is something that would require agreement with the non-National Grid TOs. They would need to be confident that the modelling approach proposed for identifying constraint costs is robust, and would need confidence in the scope for the scheme to deliver value to their customers and shareholders without undue exposure to risks outside their control.

488 This is therefore something that we will continue to discuss with Ofgem and the TOs over the coming months.

BSIS: Annual Model Review

Overview

489 This section sets out a proposed annual review process to ensure that all the SO incentive models remain current and reflective of the environment in which we operate. This process provides an additional uncertainty adjuster to the incentive framework whereby any model inaccuracy can be rectified in a transparent and auditable manner.

490 Examples of such amendments required to the models throughout an 8 year framework could include software version updates, ex ante input inaccuracies and regression data. The review process will reduce scope for windfall gains and losses to the end consumer over the RIIO-T1 period where model development work undertaken prior to scheme commencement cannot necessarily cater for all unforeseen events of the future.

Background

491 Experience in operating with the current scheme models, particularly the newly procured Constraint model, has shown that modelling and input inaccuracies can materialise throughout the scheme period which result in windfall gains and losses to the consumer. This is contrary to the principles underpinning the approach to incentivisation where the NETSO should be incentivised on those areas that we can control and/ or forecast on behalf of the consumer.

492 The current scheme has been in operation for a 14 month period and is a two year scheme. The fact that modelling inaccuracies have resulted in windfall gains and losses during that relatively short period introduces significant risk associated with the transition to longer term incentive schemes. It is therefore critical that in moving to a longer term incentive framework there are safeguards in place to protect both National Grid and consumers from any windfall that is brought about by modelling inaccuracy. A regular review mechanism should provide this safeguard and ensure that the incentive cost targets being modelled are reflective of actual operating conditions against which our actions can be compared. This is vital in order to demonstrate the value that we bring as the NETSO in reducing the cost of system operation to the consumer.

493 To provide an example of current scheme modelling issues, we have identified a number of inaccuracies within the Constraint model to date that are a combination of:

(a) Ex ante input inaccuracies which we believe cause the Constraint model to over or under forecast actual market and operating conditions on the Transmission system; and

(b) The calculations and optimisation within the Constraint model itself (i.e. the software and its setup).

494 A more specific example of where ex ante inputs may require updating is that the Constraint model uses a number of ex ante commercial generator parameters, including start up/ shut down costs and efficiency factors, to determine the unconstrained generation schedule. Whilst these parameters are treated as ex ante, they have been provided as a dataset by Redpoint based on historic generator running and therefore, over time, will require amendment to ensure latest running patterns are captured.

495 In order to ensure that the model remains accurate, particularly in terms of modelling generation patterns of key generators that impact on major system constraint boundaries, it will be important to review actual running patterns versus modelled.

496 Currently there is no mechanism to easily rectify this type of issue within the current scheme design other than to consult with the industry[50] to change the relevant modelling methodology.

497 Stakeholders have told us that the models require regular reviews to ensure they are incorporating the changes which are occurring in the industry and therefore providing a relevant incentive target. A number questioned why the models could not automatically be updated following “significant events” that are outside of our control. All stakeholders said that any proposed changes would need to be communicated through a transparent engagement process

498 Therefore in order to ensure that any such modelling issues are detected, reported and resolved over the course of the RIIO-T1 period in a timely, flexible and transparent manner, we propose an annual model review process as set out below.

Annual Review Process

499 We will continue to monitor performance of the models against the costs incurred in operating the system on a monthly basis, as we do now for the current scheme. Where significant differences arise between the forecast target cost produced by the model and the actual cost, in either direction, the reasons for these will be investigated and the drivers of the differences identified. Where these differences arise from inaccurate ex ante modelling parameters or model settings (rather than actions we take to manage costs) then methods of updating the models to correct for these differences will be investigated subject to the following principles:

(a) The change better reflects market activity outside of our control;

(b) The change does not fundamentally alter the principles of the existing methodology; and

(c) The change looks to better align the model and relevant methodologies.

[50] There is a modelling methodology change process set out in the licence (Schedule A to Special Condition AA5A, Part B) which requires us to consult with the industry before Ofgem determines whether the change can be made to the methodology.

500 These changes, along with their estimated materiality, will then be presented on an annual basis to both Ofgem and the industry one month prior to the end of each incentive year[51]. Upon expiry of 28 days, the amendment will form part of the forward looking enduring model unless the Authority directs that the revision is not made.

501 The amendments will be used to recalculate the target for the previous year. In the event that the materiality associated with the modelling amendments is greater than a £2m threshold, these will be applied retrospectively to the previous year of the incentive scheme in order to resolve any windfall gains or losses associated with the amendments.

502 Where an issue is identified that arises from an unforeseen model development which requires the principles of the existing methodology to be changed, a review will be carried out at the next mid phase review point. This is explained further in the 'BSIS Scheme Design and Governance' section.

Areas of potential change

503 There may be many unforeseen reasons why the mechanism set out above is triggered to enable changes to the scheme models. However, some examples of the types of changes that may come about are listed below. It should be noted however that this list is not necessarily exhaustive.

Software and Hardware Versions

504 In terms of the Constraint model, the current incentive scheme uses the same software version today as it had at the scheme start and runs on specific processors. The reason for this is that operational experience has highlighted that updating the software (or running it on a different processor) results in different costs being calculated by the optimiser.

505 For an 8 year incentive framework, it is not practical to maintain a static model in terms of software version and hardware and hence these will need to be updated at appropriate intervals throughout the scheme duration. The proposed process set out above should allow such software version updates to be reviewed annually such that it is kept current, and any hardware developments made to support the software as appropriate.

506 The Constraint model is a very powerful optimiser and hence a complex tool to setup, maintain and operate. Operational experience has demonstrated a need to correct various technical parameters such as the one described in the background section above.

507 In addition, the Energy model contains a sizeable portion of non-model functionality[52] to facilitate operation and updating of model. These elements of the Excel spreadsheet will require updates as required in order to improve and maintain the efficiency of model operation. If such a change were to affect the model output it would be presented in line with the process set out above.

[51] 1st April to 31st March inclusive
[52] Such as aspects of the spreadsheet that internally present tabulate results or extract data from Oracle databases.

Regression Coefficients and Relationships

508 As set out in the 'Energy Modelling' section, the energy model comprises a number of modelled relationships between variables in order to derive a target cost for each component. These relationships have been determined based on the latest historic datasets available to us in order to capture and take into account the most recent operating behaviour. However, it would be inappropriate, for example, to continue to use regression coefficients during the 2013/14 incentive year that were derived from 2005–2011 data due to the number of potential changes affecting the energy markets between these periods.

509 There will therefore be a requirement to review and refresh the regression coefficients on an annual basis as the scheme progress such that the cost target produced by the model is in line with the most recent market experience. This means that the most recent datasets available will be used to determine the model regression coefficients throughout the RIIO-T1 period on a rolling yearly basis.

510 Where any annual review of the models shows that any of relationships require a more fundamental review (i.e. that the variables used to derive the regression coefficients no longer adequately explain the cost drivers in question) then this review will be carried out at the next mid phase review point. This is explained further in the 'BSIS Scheme Design and Governance' section.

Ex Ante Model Inputs

511 Aside from model regression coefficients, there may also be instances where direct ex ante inputs to the models require updating such that they more accurately reflect the behaviour of the market. An example of this would be in the Constraint model unconstrained mode where a generation schedule is determined on the basis of market fundamentals and plant parameters.

512 These parameters include, for example, efficiency factors for different plant types which can therefore impact whether the model runs the plant (or not) in the unconstrained schedule. If the efficiency factor within the model is sufficiently different from reality, the result might be that the modelled generator output differs from the observed operating pattern of the generator. This in turn means that the target cost of constraints is artificially affected by the input error.

513 In terms of the constraint model, there may also be amendments made on an annual basis to ensure that the modelled network we operate as NETSO is consistent with the real NETS. Therefore, for example, additional constraint boundaries may be identified and input to the model throughout the RIIO-T1 period to reflect the system actual constraints that are experienced. Similarly, other boundaries might be removed (or amended) following network reinforcement.

Summary

514 The annual review and investigation process should therefore highlight any amendments required to such inputs which, in the case above, may require adjustment to ensure that the model is reflecting reality as far as possible. This will ensure that the models remain as accurate as possible over the course of the RIIO-T1 period.

BSIS: Black Start

Overview

515 Black Start (BS) is a vital service which provides the NETSO with the capability to re-energise the NETS in the event of a total or partial system shutdown. Forecasting BS costs has historically been challenging as contracts are negotiated on a bilateral basis and costs differ depending on individual station characteristics and the precise timing of the introduction of new contracts. As such, it has historically proven difficult to develop an appropriate target value to create a meaningful incentive around this service. We recognise however that we are best placed to manage the costs of the BS service and are able to influence these costs through effective management and co-ordination of service procurement. We propose therefore that BS incentives should continue to form part of the overall BSIS arrangements, but with a target cost being determined through a market-based approach rather than the current station by station cost approach.

516 De-coupling revenues from specific purchasing decisions provides better incentives for us to strike the appropriate balance between retaining legacy contracts and / or entering into contracts with new service providers. It also provides us with incentives to innovate, including for example to support alternative sources of BS service which may prove to provide better value for money to consumers in the longer term, and to trade off the various costs associated with the provision of BS services, for example the costs of black start warming which have become increasingly material over recent years.

Background

517 Society increasingly relies on electricity as an integral part of daily life, and the need to maintain the capability for rapid system restoration in the event of a system shutdown will become increasingly important as decarbonisation of the GB energy footprint drives greater reliance on electricity to meet the nation's energy needs. BS services are procured from large power stations capable of starting up in the absence of an external electricity supply.

518 Since the introduction of licence Special Condition AA5J[53], we have published a statement[54] on our website that sets out our approach to determining and procuring an economic and efficient level of BS service provision on an ongoing basis. This section sets out an incentive option to manage BS costs, in accordance with the principals laid out in that statement.

519 Currently, [text deleted] generating stations are contracted to provide BS services, consisting of legacy and new contracts within [text deleted] defined BS zones across Great Britain. With a number of legacy service providers expected to decommission their plant over the RIIO-T1 period, there is a need to replace these contracts with new BS service providers. Similarly, the

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[53] Licence Special Condition AA5J: Requirement to develop the balancing services activity revenue restriction in relation to external costs for new BS service provision

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

remaining legacy contracts will also need to be re-negotiated to re-assess contracting value and costs. Competition for BS service provision is limited, and securing agreements which provide maximum value for consumers can prove a time consuming and challenging process, which does not necessarily result in a contract being struck.

The impact of de-carbonisation

520 The move to a decarbonised economy is changing the generation landscape. This changing plant mix will have a bearing on the cost and provision of BS services. Renewable energy targets are driving substantive changes, with greater levels of intermittent generation, new nuclear plant and interconnection capability and 17GW of coal and oil plant closures as a result of the European Large Combustion Plant Directive (LCPD).

521 Amongst the current fleet of [text deleted] BS stations, a number have opted out of the LCPD and will therefore close within the RIIO-T1 period, resulting in the unavailability of a Black Start service. These LCPD opted out stations are not running for long periods of time, and this is likely to continue up to their closure. A large number of new providers will be needed over the RIIO-T1 period to replace decommissioned stations and maintain service availability. These new providers will need to invest in the capability to provide a BS service, which will result in an increase in cost compared to the legacy arrangements.

522 BS costs form part of the commercial and ancillary service contract costs included within Incentivised Balancing Costs (IBC). For the current scheme, an ex ante target was agreed based on a forecast of expected costs over the incentive period. The target was set below the forecast, and we are expecting costs to outturn higher than that target.

523 In our discussions with stakeholders at our February 2012 workshop, many questioned how much influence we actually had over the BS service. Many concluded we had little influence and therefore questioned the relevance of the current incentive. A number also commented that there is a lack of transparency surrounding contracting for Black Start and the prices currently paid to service providers.

Black Start Cost drivers

524 There are 5 cost categories associated with the service which may apply at different stages of a BS contract.

Feasibility Studies:

(a) When identifying potential providers, we may agree to provide a contribution towards feasibility studies to determine technical capability of the plan to provide BS and to help stimulate competition for the service.

Capital costs:

(a) As part of the feasibility study, potential providers will identify capital assets required to develop a new BS service. This is likely to involve the installation of new equipment. The capital costs required will be mainly driven by the size and type of auxiliary unit. Typically, this would be a small OCGT capable of supplying the auxiliary systems of the power station, thus enabling the main generating units to start. The BS service provider will seek to recover these costs through a BS contract, either as an upfront payment or over the duration of the contract. Legacy providers with ageing plant will typically look to invest in the refurbishment or replacement of this equipment to provide a new BS service going forward, and again recover these costs through the contract.

Availability Fees:

(a) The availability of BS services is a function of each station's running arrangements and determined by commercial considerations.

Testing Fees:

(a) BS testing is an important part of ensuring BS preparedness. We carry out BS tests to enable contracted stations to demonstrate their technical capability to provide a viable BS service. Testing costs can be considerable because of the requirement of the unit under test to be shut-down as part of the test and energy replaced accordingly.

Warming Costs:

(a) If a station is not running or able to synchronise at short notice, it is effectively unavailable to provide a BS service. To ensure stations are available to provide a BS service, it has become increasingly necessary to warm 'out of merit' power stations by taking balancing actions, so that they are in a position to provide the service if required. The associated costs of such actions have increased considerably in recent times.

Uncertainties in Black Start Costs

525 As is the case with many other balancing services costs, the future costs of BS are difficult to predict, but our actions can have an influence over their level. In the case of BS, there are a number of material uncertainties over the future level of costs. These include:

(a) Material uncertainties over the price and duration of both new contracts and service extensions under existing contracts given the increasing demand for value-based, rather than cost-based remuneration, for service provision as fully depreciated plant decommissions;

(b) The drive towards a low carbon economy means that many existing providers will be exiting the wholesale energy market and will need to be replaced with new service providers;

(c) Legislation such as LCPD and the government's renewable energy targets will further increase the year-on-year uncertainties over which existing providers will exit the market or mothball their plant;

(d) Difficulties over predicting the timescales for contract renewals and the time to conclude new service contracts;

(e) Limited competition in the provision of BS services given the requirement for a geographic spread of BS provision. In the shorter-term, an increasing reliance on warming to ensure the service capability of low-merit service providers, and increasing demands for refurbishment and capital asset replacements from such provides;

(f) Issues over the management of contract cancellation fees, in place in certain agreements entered into around vesting; and

(g) Ongoing uncertainties over BS testing costs, particularly the uncertainty over the market value of lost generation exports when tests are carried out.

The Challenges for National Grid

526 Despite the above uncertainties, it is essential that we continue to procure an effective and efficient BS service, and our actions can influence the costs we incur in procuring this service. The scope of actions that we can take in relation to this service is considerable and include, for example:

(a) Continuing to ensure that contracts are negotiated to secure the best value for consumers and deliver an effective service through the management of existing contracts, the development of new contracts and seeking to promote competition in the provision of new service offering;

(b) Developing alternative ways of delivering BS services, including possible DNO solutions, and seeking new types of service provider (such as nuclear stations, renewables and interconnectors) and managing the interactions between BS and other balancing services;

(c) Managing the costs of BS warming and testing in the balancing mechanism or through additional balancing services contracts; and

(d) Balancing the costs and service quality associated with BS contracts that have ‘near’ end of life assets (i.e. potentially requiring replacement, refurbishment and warming costs) compared to new service providers.

Proposed BS Incentive

527 The proposed approach to incentivising BS for RIIO-T1is based on setting a cost target based on a set of pre-agreed assumptions. This differs from the current approach of building a target based on current contract costs. It is also structured to require us to be able to appropriately balance the costs of different BS service provision, for example taking a view on whether to put in place a new service contract (and incur new capital costs), or to seek to extend an existing contract (and incur potentially lesser refurbishment or replacement costs, but also additional warming costs).

528 Under this proposal, BS will continue to form part of the wider BSIS scheme. It will be subject to the overarching 8 year framework, with the same sharing factors and methodology review points as the main BSIS scheme identified in the ‘BSIS Scheme Design and Governance’ section of these proposals.

529 As such it is proposed that the target cost for BS be determined using the following principles:

(a) Annual targets set within an eight year framework;

(b) Black Start costs will, over time, tend toward the new entrant price as existing providers seek to re-value their service. Annualised new entrant costs are therefore used as the starting point to set targets;

(c) [X] providers per zone will be required. There are [Y] black start zones;

(d) Annualised costs to include an adjustment for succession planning (i.e. to reflect the fact that new service providers need to be appointed prior to the departure of existing providers);

(e) Annualised cost to include a further adjustment to reflect the annualised cost of feasibility studies, assuming an average of [text deleted] feasibility studies per contract, and an average contract duration of [text deleted] years;

(f) A downward adjustment to be made to reflect that some providers are on legacy contracts and are not yet equivalent to the new entrant cost. This adjustment would be based on the actual ex post availability of legacy contract providers;

(g) Where legacy contracts exist, an adjustment to reflect warming costs would be made. This would be structured so as to preserve an incentive on the NETSO to manage warming costs, but adjust ex-post for actual warming volume required based on generator FPN submissions; and

(h) An allowance would also be included for testing costs (although again this would preserve incentives on us to minimise actual testing costs).

530 The outturn costs for BS which we would be required to fund from the target cost set on this basis would include:

(a) Actual costs of legacy and new contracts over the incentive period;

(b) Feasibility studies;

(c) Warming costs in the balancing mechanism or under supplementary balancing services contracts;

(d) The costs of developing alternative service and commercial arrangements; and

(e) Actual costs of testing.

Detailed Description of the Proposals

531 Algebraically, the target in any one year would be set as follows;

BS Target = {(X providers * Y zones * adjusted annualised new entrant costs)
– (legacy savings adjustment)
+ (ex post legacy warming adjustment costs)
+ (ex ante testing adjustment)} * RPI

532 The incentive proposal includes the following assumptions:

(a) The target will be indexed by RPI on an annual basis[55];

(b) An annualised new entrant cost of [text deleted], a figure based on recent BS contract negotiations. This would be adjusted to include the annualised cost of [text deleted] feasibility studies per replacement at a cost of [text deleted], reflecting recent experience of such costs;

(c) The number of stations per zone would be [text deleted] at any time. However, this number would be adjusted by a factor to reflect the fact that contracts need to be put in place on average 18 months prior to the expiry of any existing contract. This means that the average number of contracted stations in any zone at any time would be [text deleted].

(d) A downward adjustment for legacy contracts would be calculated annually. This would be based on actual payments under existing contracts, given existing contract terms. The precise amount of the legacy adjustment for each year would be determined ex post based on the actual availability of the relevant service provider under its contract. Where a material contract re-negotiation under such contracts is required, it would be assumed to move to remuneration at new entrant cost. In such circumstances, the NETSO would be incentivised to balance the costs of seeking to contract with a new provider versus seeking to extend the legacy contract, in which case we would be exposed to any additional refurbishment and asset replacement costs and any warming costs;

(e) Where target values are set by reference to one or more legacy contract costs in any particular zone, an ex-post adjustment would be made for the costs of warming, although this would be structured to preserve incentives to minimise such costs; and

(f) A fixed allowance would also be made for testing costs, based on an assumption that each service provider needs to be tested once every [text deleted] years and hence with [text deleted] stations, an average of [text deleted] tests need to be undertaken each year. Based on an average of historic testing costs, it is proposed that a testing adjustment of [text deleted] should be applied, to cover the total annual

[55] There may be a case for different indexation factors to apply to particular elements of the target.

testing costs. National Grid would be exposed to actual testing costs (including, for example the costs of any re-tests following failure, etc).

533 The table below sets out the nominal scheme targets based on new entry costs less the proposed legacy contract discounts that should be applied for each year of the scheme. These values are indicative and based on an assumed availability of 90%. In practice, it is proposed to determine the actual adjustment based on the ex-post availability of the service providers. Where a legacy contract expires (because of station closure) or is subject to a material renegotiation, it is subsequently treated as a new entrant contract. In such circumstances, we may seek to renegotiate and pay any replacement and refurbishment costs as well as any additional warming costs if the contract is renewed, or decide to strike a contract with a new provider. Where existing contracts are not subject to renegotiation (or closure) over the entire duration of the eight-year scheme, a discount has been included based on existing contract terms.

Indicative Annual Black Start Targets
Costs stated in 2011/12 prices, subject to RPI indexation

[Table Deleted]

534 Note that all values in the table above are in 2012/13 prices. As discussed above, adjustments to targets would also be made ex post for legacy warming costs, and actual legacy contract availability.

535 These figures are based on our current view of when we expect current BS service providers to close, or become substantially unavailable that it becomes more efficient to seek out a new provider. It also assumes that as legacy contracts expire, these providers will seek out the market rate for the services they provide, to cover the cost of replanting or refurbishing their assets.

Value for consumers

536 Black Start is in effect an insurance policy against the long-term wide-scale loss of the NETS, providing an essential service necessary to support restoration in the unlikely event of a major blackout. We typically contract with [text deleted] stations in each Black Start region to perform this service, and ensure that at any time, [text deleted] of these are available at short notice to support restoration activities.

537 There is a growing need to replace the fleet of Black Start providers, as legacy power stations make way for new low-carbon generation. Given recent experience of procuring new Black Start service providers, we know the cost of purchasing this essential service will continue rise through the RIIO-T1 period.

538 De-coupling revenues from specific purchasing decisions provides better incentives for us to strike the appropriate balance between retaining legacy contracts and or entering into contracts with new service providers.

539 The incentive as described above will enable us to continue to make the right economic decision for consumers over whether to enter into a new service provider contracts or extend a legacy contract which may have lower direct costs; but may require refurbishment or replacement costs and additional warming costs in the balancing mechanism.

540 The procurement of an effective Black Start service is of critical importance to the economy, consumers and society. It is essential that we are both funded and incentivised to procure this service efficiently for the benefit of consumers both today and into the future. Effective incentives will also drive us to innovate and find alternative sources of Black Start services to the benefit of consumers.

BSIS: Transmission Losses

Overview

541 We are currently incentivised to reduce transmission system losses through an ex ante target volume as part of the BSIS. This section sets out the background and drivers of transmission losses on the NETS and highlights the limited level of control and influence we have on losses. This section proposes an alternative approach for incentivising losses based on adjusting the target value ex post to account for the drivers outside our control with a view to providing a more focussed incentive.

542 More specifically, we propose to employ an ex ante volume target based on the outturn of the previous year. This target is then adjusted ex post by modelling the effect of the difference in the outturn pattern of generation and demand as compared to the previous year. An ex post reference price will continue to be used to translate the outturn volume to a cost.

Background

543 The NETS is the high voltage electricity network connecting large scale generation to demand. The flow of electricity across the NETS results in power losses in the various elements of the system, principally transformers and transmission lines. The lost power, referred to as transmission losses, can include fixed and variable losses.

544 Fixed losses occur within the iron cores of transformers and the insulation of cables and overhead lines, whenever the circuit is energised. They have historically accounted for around 40% of the total losses on the NETS. The magnitude of these losses is typically driven by the applied voltage and thus, as the voltage must be controlled within narrow tolerances and is often dictated by considerations of system security, these losses are considered to be fixed. Fixed losses are associated with the type of assets on the network and thus are to an extent capable of being influenced through investment decisions, more than through operational decisions.

545 Variable losses are due to the resistance to the flow of electrical current, leading to heating in the conductors of transformers, cables and transmission lines. The level of variable losses is therefore driven by the level of power transfers across the NETS which, in turn, is driven by the location of generation and demand. In general, the level of variable losses in a transmission line is proportional to its length and the square of the power transferred through the line. Therefore the further generation is located from away demand, the greater the power transfers and the higher the level of losses.

$$\textbf{Losses } \alpha \textbf{ (Power Transfer)}^2 \textbf{ x Distance}$$

546 On average[56], variable losses account for 60% of the total transmission system losses on the NETS. As variable losses are associated with the flow of power across the network, these are, in principle, considered to be more within the control of the NETSO through its operational decisions. However, in practice these flows are dictated primarily by the pattern of generation, which is determined by the commercial decisions of individual generators responding to market conditions and, in particular, by the decisions of generators as to where they locate new generating stations and close existing ones.

547 The quantity of total transmission losses on the NETS is calculated by the differences in the metered quantity of energy entering the system from generators and metered energy leaving the system at Grid Supply Points (GSP). We have an obligation, under our Electricity Transmission Licence[57], to report annually the level of transmission losses on the on the NETS (by TO area), as the difference between metered electricity units entering and leaving each system.

Transmission Losses Incentive

548 We are currently incentivised to reduce transmission losses compared to an ex ante target set prior to the start of the scheme. For the current scheme, the two year ex ante target volume for transmission losses is 8.9TWh, and includes a +/- 0.6TWh dead band to cater for modelling uncertainty.

549 Transmission losses are incentivised within BSIS as a component of Incentivised Balancing Costs (IBC) as outlined in the formula below:

IBC = CSOBM + BSCC + TLIC

Where:

IBC = Incentivised Balancing Cost
CSOBM = the total cost of all Balancing Mechanism actions
BSCC = the commercial and ancillary service contract costs, including trading
TLIC = adjustment based on performance against the transmission losses target

550 Note that, unlike CSOBM and BSCC, the TLIC term does not represent an actual cost incurred but is included in the calculation of Incentivised Balancing Costs purely as a mechanism for increasing or decreasing incentive payments under the BSIS scheme. Specifically, if the volume of losses outturns lower than an agreed target, incentivised costs are adjusted downwards, increasing the BSIS incentive payment whilst, conversely, if the volume of losses outturns above the agreed target, incentivised cost are increased, thus reducing the BSIS incentive payment.

[56] At times of system peak, variable losses can be relatively higher due to higher flows across the system.
[57] Special Condition AA5C

551 To translate the quantity of losses into a cost to be applied to IBC, the current incentive uses the average ex post power price (SPNIRP) for the incentive period.

Forecasting Transmission Losses

552 Despite our best efforts, we have not been able to forecast transmission system losses with any degree of accuracy. This is because the level of transmission losses is determined to a large extent by the pattern of generation, which is itself dictated by generation economics and market conditions that constantly evolve. Whilst the Constraint model with a full nodal model might be able to model variable losses accurately given the pattern of generation, it would not necessarily help to accurately predict generating bidding behaviour on which the pattern of generation will depend. Accordingly, a full nodal model in the Constraint model does not form part of the proposal for an incentive scheme for transmission losses commencing April 2013.

553 For the current BSIS scheme, a target quantity for the losses element was derived on the basis of historic losses outturn figures in conjunction with a forward looking view of:

(a) The location of commissioning generation, with new generation connecting in the North and Scotland tending to increase losses but offset by high load factor new generation in the South;

(b) Anticipated transfers across southern interconnectors (exports from the UK to the continent will increase losses); and

(c) New transmission infrastructure that resolves transmission constraints, thereby enabling increased power flows over longer distances, thereby increasing losses.

554 Other drivers of losses include, for example, variations in zonal generation patterns, growth in southern generation, the level of Scottish exports to the E&W system, the level of part loaded plant, reduced flows directly out of concentrations of generation (e.g. Drax, South Humber Bank, Killingholme) and the degree of geographic dispersal of generation and demand growth.

555 For the current incentive scheme it was envisaged that newly commissioned CCGTs in the South would achieve high load factors over the 2011-13 BSIS period, potentially offsetting some of the increased power flows that were expected across the reinforced Cheviot boundary (due to increased wind generation in Scotland). Following discussions with Ofgem, a target for losses was agreed based on the impact of new southern generation being greater than originally envisaged and the expected connection of renewable generation in Scotland being lower than originally expected.

556 In practice, changes in spark spreads, and delays to the commissioning of new plant, have meant that gas-fired generation in the South has not operated as anticipated, and has typically been replaced by coal-fired generation in the North. This, amongst other factors, has led to losses being higher than expected at April 2011 when the target was set, thus leading to a windfall

(financial) loss under the incentive scheme, as a result of events outside of our control.

557 At the stakeholder engagement workshop in February, our stakeholders were generally not supportive of retaining a transmission losses incentive. They questioned why losses are included in the current SO incentive scheme because they did not believe we could influence losses.

"I can't see the reasons for incentivising the SO for [reducing] losses at all."
Electricity SO Incentives Stakeholder Workshop, 23 February 2012

Losses under the RIIO-T1 Period

558 The transmission network will change over the next decade as the generation of electricity is decarbonised. During this period:

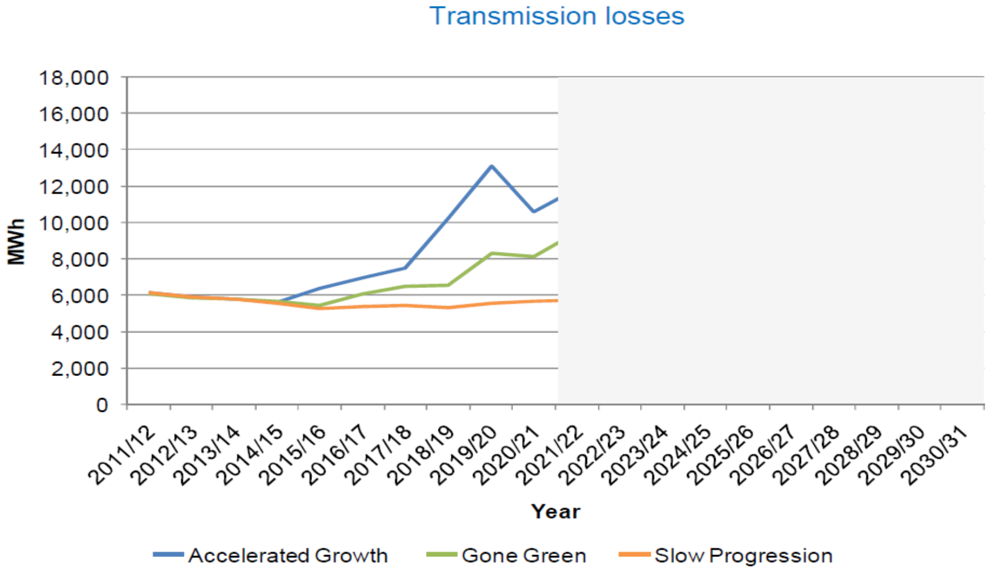
(a) ~17GW of coal and oil plant is expected to close, mainly driven by the European Large Combustion Plant Directive (LCPD);

(b) 26GW of wind generation (much of it in Scotland and offshore connected at the periphery of the system) is expected to have commissioned; new gas generation and Combined Heat and Power (CHP), solar power and other generation types embedded in the distribution networks; and

(c) New nuclear generators may also commission towards the end of this period.

559 With the expansion of the transmission network to connect new sources of generation at the extremities of the network to replace generation located closer to the centres of demand, the quantity of losses will increase. In addition, increasing levels of interconnection with neighbouring systems with closer market coupling will mean that the interconnector flows are likely to become larger and more volatile, and will increasingly impact on the volume of losses incurred on the NETS.

560 The graph below shows how transmission losses are forecast to increase substantially out to 2021/22 under the two of the three scenarios which underpin our RIIO-T1 submission, with forecasts beyond 2021/22 being subject to even greater uncertainty.



561 Thus our ability to forecast ex ante the level of losses is going to decrease with changes to the market and hence forecasts will be even less reliable for the RIIO-T1 period than for previous schemes. Thus, such forecasts are highly unlikely to provide a robust ex ante target for an 8 year incentive scheme.

562 This was discussed at our stakeholder engagement workshop in February where stakeholders agreed that the natural consequence of increasing connections of both onshore and offshore wind farms in locations more remote from demand, particularly in Scotland, will be that the volume of losses will increase.

Controlling Transmission Losses

563 As NETSO we can, in principle, alter power flows across the NETS and hence influence the volume of losses using the Balancing Mechanism (BM), where we can increase (Offer) or decrease (Bid) generation to balance the system. For example, we could accept Bids to reduce generation remote from demand centres such as that in the north of Scotland (namely wind power), and Offers to increase generation closer to demand centres; such as that located in the south of England (gas, coal or oil plant). However such actions are not permitted under our transmission licence and whilst reducing losses, could be regarded as inconsistent with Government objectives of a de-carbonised energy sector.

564 Our transmission licence requires us to co-ordinate and direct flows onto and over the transmission system in accordance with the NETS Security and Quality of Supply Standards (SQSS), taking only price and technical differences into account in choosing between providers of balancing actions. This does not permit balancing actions to be taken to reduce transmission losses. Instead, having taken transmission system security and generator technical characteristics into account, balancing actions must be taken in strict price order.

565 Even if we were permitted to re-despatch the system taking account of losses, the scope for reducing losses economically in this manner is extremely limited.

The marginal cost of accepting a Bid to reduce output at plant remote from demand centres and accepting an Offer to increase output at plant located closer to demand centres, will in the vast majority of cases, be higher than the savings in losses this would achieve, even taking into account the cost of carbon. We therefore believe the scope for re-despatching plant economically to reduce losses is extremely limited, and much smaller than the likely error in setting a robust ex ante target for an incentive scheme.

566 Stakeholders agreed that the market delivers generation patterns to meet demand based on market economics and that this was the key driver behind transmission losses and this is outside of National Grid's control. It was noted by stakeholders that our actions in the BM have very little influence on the level of losses and the opportunities to account for losses in the BM, in conjunction with meeting other NETSO requirements, is very limited. They therefore concluded the incentive on losses does not have influence on our actions in the BM or our behaviour as the NETSO.

567 Nevertheless, the effect of losses can be and is taken into account in the design and procurement of transmission assets. Our policy has been to purchase equipment that has been designed to minimise lifetime operating costs including the expected cost of transmission losses. This is achieved by notifying equipment manufacturers how the loss performance of their equipment will be assessed in tender evaluations. Manufacturers can then optimise the design of their equipment to best meet the capital plus lifetime cost assessment.

Setting an incentive target for Transmission Losses

568 Whilst there are many factors which affect losses, the main drivers of increased transmission losses will continue to be changes in the pattern of generation and interconnector usage. Our ability to forecast these accurately in the medium to long-term is limited. Nevertheless, losses represent sizable cost to the industry and therefore to consumer bills, and whilst our scope to minimise losses is small, we acknowledge that we are better placed than consumers or other industry participants to manage these costs. To this end we have developed a proposal whereby we continue to be incentivised around transmission losses.

569 Given the challenges set out above in developing a robust set of ex ante targets for an 8 year incentive scheme, we propose an approach which adjusts the target value for losses ex post by modelling the effect of the difference in the outturn pattern of generation and demand as compared to the previous year. In this proposal, the previous year's outturn is used as the ex ante baseline for setting the target in the following year.

570 Using this approach, the annual target for transmission losses would be calculated as follows:

$$TARGET_t = TL_{t-1} + \Sigma_i \, TLF_i \, (G_{t,i} - G_{t-1,i}) + \Sigma_i \, TLF_i \, . \, (D_{t,i} - D_{t-1,i})$$

where TL_{t-1} is the outturn volume of losses for year t-1;

$G_{t,i} - G_{t-1,i}$ is the metered generation output at each node in years t and t-1;

$D_{t,i} - D_{t-1,i}$ is the metered demand at each node in years t and t-1; and

TLF_i is the Transmission Loss Factor for generator or demand at each node.

571 Transmission Load Factors (TLF) would be calculated ex ante based on the load-flow analysis similar to that proposed for Balancing & Settlement Code Modification Proposal P82[58] i.e. based on a methodology that was explored and debated extensively by BSC Parties. There would be a single generation and demand TLF calculated for each node to apply throughout the year, based on an aggregate view of the expected level of transmission capacity available. These would be recalculated annually, as part of the annual model review process, to take into account any network reinforcements. Similarly, new nodes would be added to take account of new generation/demand and any extensions to the NETS.

572 If the nodal TLFs are considered to be overly complex and lacking in transparency, a system of zonal TLFs could be used instead. To some extent, though, the simplicity is superficial, as the P82 methodology uses nodal TLFs in order to derive zonal figure.

573 We believe that this approach will make a significant contribution to accounting for changes in losses due to year-on-year changes to the locational patterns of generation and demand (including the effect of interconnectors). It is not clear without further work and experience, the effect of the granularity of TLFs time-wise, as well as nodal vs. zonal. Consequently, it will likely be appropriate to revisit the methodology used to calculate the target periodically, ideally at the same time as the proposed BSIS review points.

Calculating Incentive Payments

574 As with the existing BSIS, incentive payments will be determined by calculating the Transmission Losses Incentivised Cost (TLIC) from the difference in actual and target losses, and using the transmission losses reference price (TLRP) derived as now:

$$TLIC = TLSF * \Sigma_t (TL_t - TARGET_{t}) * TLRP_t$$

Where:

TL_{t-1} is the outturn volume of losses for year t-1;

$TLRP_t$ is the Transmission Losses Reference Price; and

TLSF is a Transmission Losses Sharing Factor.

Given:

[58] P82 (Introduction of Zonal Transmission Losses on an Average Basis) proposed that the BSC be modified to give effect to a zonal differentiation in the allocation of the volume of transmission losses. P082 - ELEXON

(a) the large risk that previous experience has demonstrated that we are taking in respect of any incentive against transmission losses;

(b) the factors that are likely to make future patterns of generation and demand ever more difficult to forecast;

(c) the unproven nature of the proposed correction mechanism; and

(d) the limited scope we have for controlling transmission losses.

575 We propose the application of a sharing factor of 20% and a dead-band of 10% to account for modelling uncertainty. We remain firmly of the view that it would be inappropriate to apply the same sharing factor, and therefore exposure, to these costs as the other BSIS cost elements which are more directly within our control.

Summary

576 Our ability to forecast and control transmission losses is extremely limited, and therefore does not easily lend itself to continued incentivisation under RIIO-T1. However, we recognise losses do contribute to carbon emissions and represent a cost borne by consumers. We also recognise that we are better placed than other market participants and consumers to influence losses, albeit to a limited degree, and have therefore proposed an approach that will continue to place an incentive on National Grid to manage losses.

Renewable Generation Forecasting Incentives

Overview

577 Over the next decade, installed capacity of wind power connecting to the NETS is expected to increase from the current capacity of 4.5GW to 26GW. As a result, the focus on wind forecast accuracy will become paramount.

578 In line with Ofgem's proposals, it is therefore timely to propose an incentive scheme which seeks to improve the timeliness and accuracy of wind forecasts. It is proposed that this should be achieved by targeting the mean absolute error associated with our wind forecasts, whilst at the same time increasing the frequency with which such forecasts are produced.

579 The majority of stakeholders support the drive for more accurate wind forecasting. A couple of stakeholders did express a view that as more wind generation is developed and technology improves, forecasting could become easier so any incentive will have to be kept under review.

580 We propose phasing in additional forecasts of aggregate national wind power output, increasing the current one forecast per day up to four per day. We will also engage with stakeholders in order to define suitable regions to use as the basis for regional forecasts.

581 We propose a financial incentive in the range +/-£250k per month, over a scheme duration of 8 years, although it is proposed that a review of the operation of the scheme should be undertaken after 4 years.

Background

582 The variability and unpredictability of wind power, relative to other forms of generation, has meant that National Grid has been less able to rely on the Final Physical Notifications for wind generation submitted by generators as these have proved to be relatively unreliable and subject to re-declaration at short notice. Consequently, as the amount of wind power on the system has become significant, we have been making our own forecasts of wind power so that we can manage our balancing activities, in particular the holding of reserves from other forms of generation.

583 In addition to making use of these forecasts internally, we have been making these forecasts available to the market. Market participants – both wind-powered and other generation – have found this information useful in trading out their own positions and anticipating our likely requirements for balancing actions.

'We view the current wind forecasts that National Grid publishes an integral part of the information provided on the system length and therefore an insight into the likely system operation actions that National Grid may take.' **Renewable Generation Forecasting and Information Provision Consultation, April 2012**

584 As wind power capacity increases, the effect of wind power unpredictability will increase and our wind power forecasts are likely grow in importance both to own operations and to market participants.

'as new technologies penetrate the market and make up significant parts of the UK energy mix, it will be important to understand the impacts these have upon the market and network operations.'
Renewable Generation Forecasting and Information Provision Consultation, April 2012

585 Accordingly, Ofgem set out a view in its January 2012 consultation on the SO incentives to apply from 2013 that we should have a new financial incentive relating to the accuracy of our wind generation output forecast and the timeliness and availability of the information on our website.

Current Process

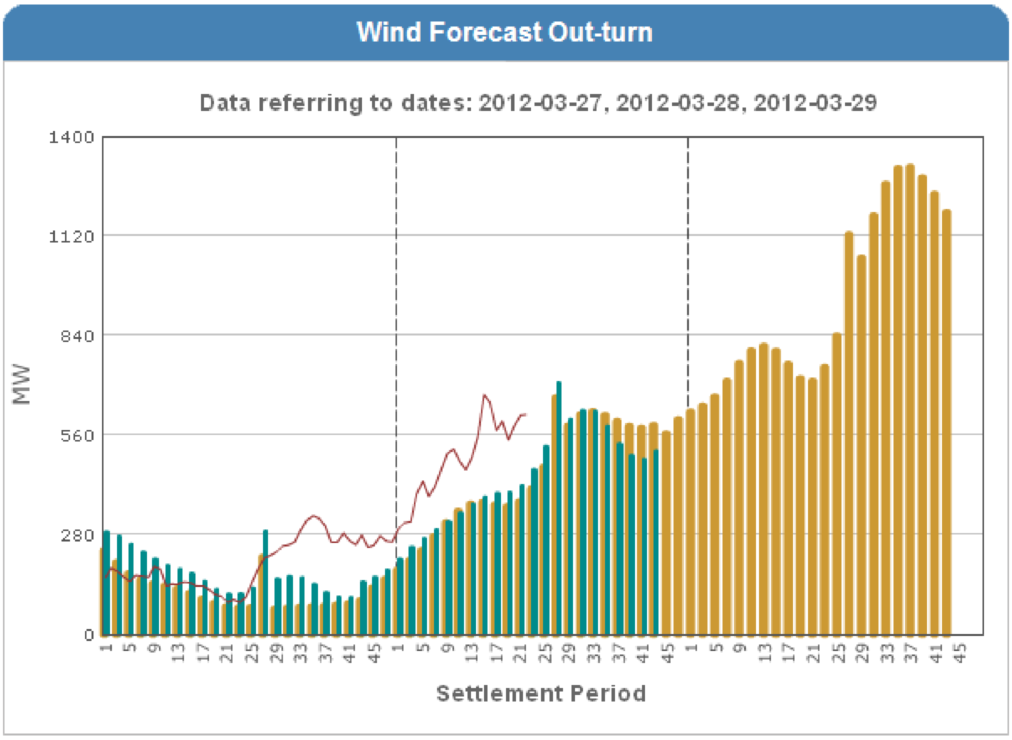
586 Currently we produce forecasts for internal use four times a day. We receive wind speed predictions from our meteorological data provider at 3am, 9am, 3pm and 9pm GMT. Using these wind speed predictions, combined with data on the characteristics of wind turbines we calculate a predicted output of each wind generation BM Unit. From these individual predictions we calculate a national aggregated wind power forecast for each Settlement Period in the following 72 hours.

587 These forecasts are typically produced within two hours of the receipt of the meteorological data, i.e. at 5am, 11am, 5pm and 11pm GMT, and are used by our control room engineers to schedule pre, and anticipate post, Gate Closure balancing actions.

588 Currently we provide the 5pm forecast for publication on the BM Reports[59] website, which is maintained by Elexon for the purpose of disseminating real-time information to market participants and other interested parties. The forecasts consist of the expected aggregate wind power generation for each Settlement Period in each of the following two Settlement Days. We provide operational metered data also, giving an indication of aggregate actual output for comparison with forecasts well in advance of Settlement timescales.

[59] NETA Reporting

Wind Forecast, Revised Forecast and Outturn on BM Reports Website



Wind Power Forecasting Performance

589 Our current wind power forecasting system was commissioned in April 2011 and has been producing daily forecasts since then. Forecasting performance statistics are produced and monitored on a monthly basis. These comprise:

(a) **MW Capacity**, being the installed capacity of wind generation which, although not an error statistic per se, is used as the basis for calculating the various error statistics in percentage terms. This figure changes each month as new wind turbines are commissioned;

(b) **Mean Error and Mean Error %** being the total error, netting under and over forecasts and giving an indication as to whether consistent bias has occurred during the month. The percentage figure is derived by dividing the Mean Error by the MW Capacity;

(c) **Mean Absolute Error and Mean Absolute Error %** where under and overforecasting errors are both counted positively and gives a commonly used measure of the reliability of forecasts in each Settlement Period;

(d) **Max Underforecast and Max Underforecast %** being the largest underforecasting error in the month and generally occurs during periods of high wind speed when shut downs, which are difficult to forecast precisely, are most likely to occur; and

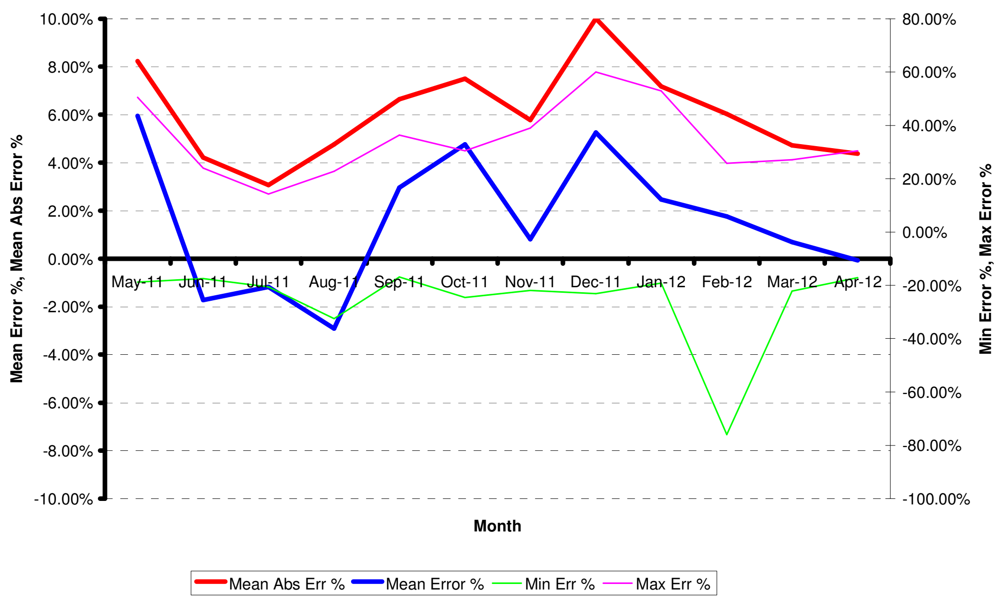
(e) **Max Overforecast and Max Overforecast %** being the largest overforecasting error in the month and generally occur when the timing of the arrival of a weather system is not as expected.

590 Statistics are computed internally for a range of time horizons. Accuracy of the forecasts for the following Settlement Day, since the systems were commissioned in April 2011, is shown in the table below.

Wind Power Forecast Errors

Month	Installed MW	Mean Error (MW)	Mean Error %	Mean Abs Error (MW)	Mean Abs Error %	Max U/Fcst (MW)	Max U/Fcst %	Max O/Fcst (MW)	Max O/Fcst %
May-11	3498	208	5.95%	288	8.23%	-659	-18.84%	1767	50.51%
Jun-11	3888	-67	-1.72%	164	4.22%	-680	-17.49%	930	23.92%
Jul-11	4016	-47	-1.17%	123	3.06%	-827	-20.59%	571	14.22%
Aug-11	4016	-117	-2.91%	191	4.76%	-1303	-32.45%	915	22.78%
Sep-11	4016	119	2.96%	267	6.65%	-676	-16.83%	1461	36.38%
Oct-11	4016	191	4.76%	301	7.50%	-986	-24.55%	1227	30.55%
Nov-11	4016	33	0.82%	232	5.78%	-881	-21.94%	1566	38.99%
Dec-11	4016	211	5.25%	402	10.01%	-930	-23.16%	2412	60.06%
Jan-12	4140	102	2.46%	297	7.17%	-792	-19.13%	2194	53.00%
Feb-12	4140	73	1.76%	250	6.04%	-3144	-75.94%	1069	25.82%
Mar-12	4559	32	0.70%	215	4.72%	-1008	-22.11%	1232	27.02%
Apr-12	4653	-3	-0.06%	204	4.38%	-797	-17.13%	1417	30.45%

Day Ahead Wind Forecasting Errors



591 From both the forecasting performance statistics and from our experience of making the forecasts, we observe that forecasting performance has seasonal variations, with mean absolute errors, for instance, being highest in winter.

592 Whilst we believe that our forecasting techniques are improving, we believe that going forward the task of forecasting is likely to become more complicated, in particular, with:

(a) Evolving turbine technologies changing the relationships between wind speeds and wind turbine output, requiring our models to be constantly updated and improved and more varied in order to maintain forecasting accuracy;

(b) The increase in offshore wind generation changing the characteristics of our forecasts as there is less experience with offshore wind speed forecasts and less data with which to verify them;

(c) Changing weather patterns;

(d) The rapid increase in installed wind generation capacity ahead of the associated transmission infrastructure will result in some curtailment due to limitations in the available transmission capacity. These factors will mean that wind generation output will no longer depend on just wind speed and plant dynamics, but will also need to take account of various complex system issues; and

(e) Increasing incidence of wind powered generation providing balancing services and wind powered generation with built-in energy storage, again, complicating the relationship between wind speeds and wind power output.

Proposed Approach

593 In recognition of the value of our forecasts to market participants, we propose a two fold approach:

(a) First to increase the number of forecasts provided to the market to two per day in 2013/14, rising to 4 per day by 2015/16 in recognition of the increasing role of wind power in the market; and

(b) An incentive to drive improvements in the timeliness and accuracy of these wind forecasts, focussing on absolute mean % error of the day ahead wind forecasts.

594 We propose also to provide regional forecasts subject to the views of stakeholders as to the appropriate definition of such zones. We will thus consult with stakeholders, discuss the responses with Ofgem, and define appropriate forecast regions. Moreover, publication of new forecasts will depend on Elexon procuring the necessary developments to the BM Reporting Service (BMRS) and hence the provision of such forecasts to Elexon should be linked to the BMRS's ability to receive and publish them.

595 We propose that a wind power forecasting performance index is calculated by reference to the accuracy of forecasts in each month, such that:

Mean Absolute Error %	Forecast Performance Index (FPI)
< 0.5* MAE Target	+1
0.5 * MAE Target	+1
MAE Target	0
1.5 * MAE Target	-1
> 1.5 * MAE Target	-1

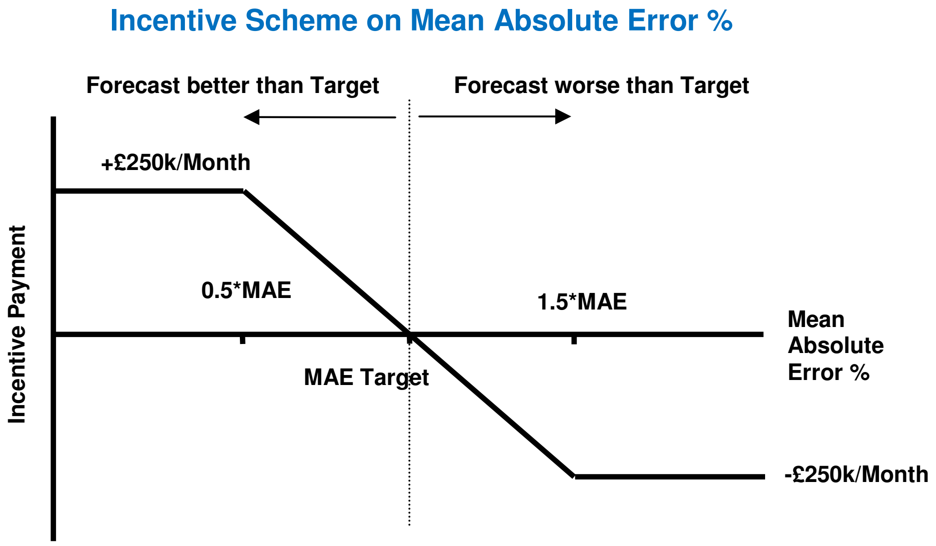
596 Where MAE Target is the target for the percentage Mean Absolute Error for the relevant month, and with FPI being linearly interpolated for percentage Mean Absolute Error values between 0.5 times MAE Target and MAE Target and between MAE Target and 1.5* MAE Target.

597 The MAE Target for the relevant month will be based on our average performance between May[60] 2011 and March 2013, e.g. the target for May 2013 will be based on the performance in May 2011 and May 2012, whilst the target for April 2013 will be based on April 2012 only. These targets will provide the incentive to maintain our focus on delivering high levels of forecast accuracy throughout the incentive period, particularly in view of the various factors that we believe are likely to make accuracy increasingly challenging to maintain and improve.

598 Targets may need to be adjusted when applied to the 4 daily forecasts, as the horizon for each of the 4 daily forecasts will be different, such that the forecasts for the following day at 5am and 11am are likely to have greater uncertainty than the 5pm forecast while the 11pm can be expected to have less.

599 Forecasting Incentive Payments for the scheme period would then be based on FPI for each month in the scheme period, with the maximum incentive payment in each month being £250k (for a forecast 50% better than the target) and the maximum loss being £250k (for a forecast 50% worse than the target).

[60] Published data is not available prior to this time.



600 Where we fail to provide Elexon with a forecast by the publication deadline of 5am, 11am, 5pm or 11pm, as the case may be, then FPI will be calculated using the previous forecast. This will implicitly give us an incentive to provide updated forecasts by the relevant deadline, as previous forecasts are unlikely to be as accurate as updates closer to real-time.

601 It is proposed that the scheme operate on a 4+4 year basis, with the scheme reviewed midway through the RIIO-T1 period to ensure it remains appropriate, focused and valued by our customers.

Further Forecasting Requirements

602 It is likely that individual market participants will have specific wind power forecasting requirements. It may be that it is appropriate that such requirements are not satisfied by modifying existing reports or producing additional reports for general publication as the required information either may be not relevant to other users or may provide data which is commercially sensitive to a particular party, e.g. the output from a particular party's wind generation.

603 We recognise that parties will be able to procure tailored services from other providers, using data from meteorological data providers and other information which may be specific to the party concerned. Nevertheless, we propose that, in addition to forecasts for general publication and which are covered under the umbrella of the wind power forecasting incentive scheme, we will also consider requests from individual market participants for us to provide forecasts tailored to their specific needs as a commercial service. We propose that this additional service would be treated under the transmission licence as an excluded service revenue restriction.

Future Developments

604 Whilst stakeholders have told us that a drive for more accurate wind forecasting is important, a number have said they receive a number of forecasts and National Grid's is of interest because it indicates to what extent the power market may be impacted by wind. Stakeholders were interested in additional wind information regarding wind cut-out and said that zonal or regional information would be of most value.

605 We are therefore currently developing and trialling a number of additional forecasts, such as:

(a) **Extending the forecasting horizon**: Within National Grid, we are producing forecasts up to 10 days ahead. As yet these forecasts are proving not always to be reliable and the value of these forecasts is yet to be evaluated;

(b) **Non CDCA Wind Generation:** In addition to power from wind generator BM Units, we estimate there is approximately 2000MW of installed wind power capacity which is embedded within Supplier BM Units and hence appears as negative demand. We have relatively little information about such generation, and do not have information about actual metered output. Thus while we do endeavour to forecast the effect of this generation on apparent demand, the reliability of these forecasts is difficult to establish;

(c) **Probabilistic Forecasting:** We are also developing probabilistic forecasts. These replace a single estimate of wind power for each Settlement Period with a probability distribution, expressed as one or more confidence intervals. Within the last 12 months we have been using these experimentally within National Grid. As yet, we do not have sufficient experience of the veracity of these forecasts as it will take some time to ascertain whether the predicted ranges of uncertainty are realistic. Consequently, no great reliance is placed on these forecasts internally and they are not yet considered of sufficient proven reliability to publish;

(d) **Cut-Out Modelling:** A special case of the probabilistic forecast is wind "cut-out" forecasting, in which we model the likelihood of wind generation shutting down due to excessive wind speeds. This is a forecast that stakeholders have specifically requested and we have been paying particular attention to the forecasting of these events, although the nature of the problem is such that small differences in wind speeds can have a substantial impact on output; and

(e) **Other renewables:** The penetration of other intermittent renewables, too, has increased to a significant level, with solar PV now accounting for over 1GW of installed capacity. We are seeking to forecast the output from these sources.

606 Currently, we do not consider that these services are sufficiently well developed and proven to offer as reliable services to market participants. Nevertheless, we will be continuing to develop these services and should it

become viable to offer these to the market they could be considered for inclusion in future incentives.

607 By the extended provision of our current forecast and the further provision of these additional forecasts, we aim in the first instance to improve the efficiency of our operations. However, in addition, the efficiency of markets is greatly enhanced by improved information. Our stakeholders have informed us that they would find improved information in order to better understand and anticipate actions in the balancing mechanism. Moreover, the timely publication of accurate wind generation forecast data will enable market participants to trade their own positions more effectively and efficiently which, ultimately, should, along with reductions in the direct costs of system operation, result in reductions in costs for end consumers.

Customer and Stakeholder Satisfaction Scheme

Overview

608 Customer and Stakeholder Satisfaction is an indicator of how well we deliver against our customers' and stakeholders' expectations of the vital services we provide. To recognise the importance of customer and stakeholder satisfaction in today's society, we have proposed a financial incentive based on a satisfaction survey and a discretionary reward for stakeholder engagement within our March RIIO-T1 business plan.

609 Ofgem have proposed that the financial incentive associated with the survey has a value of up to +/- 1% of annual revenue, and that the discretionary reward has a maximum reward of 0.5% of annual revenue[61].

610 We propose that these incentives cover both the NETSO and TO aspects of our role to align with customers' experience of how we operate as integrated provider of transmission services.

Background

611 In 2009, we recognised the need to implement a new customer strategy on the back of the evolving energy industry and changes to our customer base; as such we introduced a formal survey in 2009 to help identify potential improvements to our customer service levels. We have been working hard since then to improve our customer service and satisfaction strategies and have launched our customer commitment[62]; which sets out what customers can expect in the delivery of our services.

When asked about customer service standards, stakeholders agree that National Grid staff are experts at the 'day job' - the networks are run well and there is a high level of technical expertise. In terms of customer service, there was recognition that improvements have been made but there is still some way to go. Some attendees suggested that National Grid could still be more proactive in dealing with its customers.
RIIO-T1 Stage one workshop, Brunswick report, 23rd November 2010

612 Ofgem has proposed an incentive package to encourage the network companies' behaviour in relation to monitoring performance against outputs and driving improved customer and stakeholder satisfaction scores and improved levels of stakeholder engagement. We have developed customer satisfaction surveys that will be used to set the level of performance for this output, which align with the work we have undertaken in recent years.

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[61] The average electricity TO revenue over the 8 year RIIO-T1 period is £1,811m.
[62] National Grid: Our commitment to UK Transmission customers

Developments expected over RIIO-T1 period and TO plan Interactions

613 Within the Outputs[63] section of our March RIIO-T1 business plan, we have proposed a financial incentive relating to customer satisfaction.

614 The proposed financial incentive mechanism has the following features:

(a) The first aspect is based on the results of an annual customer and stakeholder satisfaction survey. The survey will reward companies that can demonstrate improvements in customer and stakeholder satisfaction over the RIIO-T1 period; and

(b) The second aspect will be a discretionary reward, which will incentivise performance where we can demonstrate that our effective stakeholder engagement has led to positive outcomes for stakeholders

615 The graph and table below illustrate our proposals, with the blue line on the graph representing the uncapped performance and the red line the capped performance.

Customer and Stakeholder satisfaction incentive

[63] National Grid's outputs section from the Business Plan: Outputs | Transmission: Electricity | National Grid

Possible outcomes under the customer satisfaction incentive

	Max Gain		Max Loss	
	Survey score	Max gain	Survey score	Max loss
Uncapped performance	9.00	+1.0%	4.80	-1.0%
Capped performance	7.95	+0.5%	5.85	-0.5%

616 The customer satisfaction incentive is a symmetrical incentive scheme using the absolute customer and stakeholder satisfaction score (measured on a scale of 1 to 10, with 10 being the best score), with a target (break-even point) set to our current customer satisfaction score of 6.9, and maximum gain with a score of 9.0. Since this incentive is the first of its kind and we have limited previous experience of a customer survey, we propose a degree of protection against windfall gains or losses. Our proposals[64], which will be finalised through further discussion with Ofgem, accommodate the full (uncapped) +/- 1% of annual revenue range subject to meeting pre-defined criteria which may comprise quantitative and/or qualitative measures. If these criteria are not satisfied, then a restricted (capped) +/- 0.5% of annual revenue range will be applied.

617 We are currently developing candidate quantitative and/or qualitative measure with Ofgem, and the candidate measures include:

(a) Number of complaints received in the year;

(b) Standards of service being met/missed;

(c) Response scores to particular questions within the survey (for example, responses to the questions relating to our customer commitment);

(d) Percentage of responses less than / equal to four out of 10; and

(e) Percentage of responses greater than / equal to eight out of 10.

Proposed approach

618 The survey to be carried out with our stakeholders will cover their views on NETSO and TO activities that we carry out. We propose a single customer satisfaction incentive to reflect the combined nature of our business. To separate out NETSO and TO customer satisfaction incentives would add complexity with limited material benefit.

[64] Further information on our proposals set out in the Outputs annexe of our March RIIO-T1 TO Business Plan http://www.nationalgrid.com/NR/rdonlyres/91BBEC0F-50BB-4826-B008-11B5129CC037/52184/2012_NGG_Outputs_redactedsecure.pdf

619 The proposed incentive encourages us to consider the overall impact of our actions on our stakeholders and aligns with the commitments we have already made to our customers and stakeholders. Through our customer commitment program we have published our actions in response to the feedback we have received through customer surveys.

620 Consequently, greater focus and improved customer service should improve the efficiency of our operations and deliver long term benefits and potential cost savings for the consumer.

Risk and Uncertainty

Overview

621 Under the RIIO-T1 framework, the price control settlement will be based on forecasts of output requirements, demand for network services over time, the cost of delivery (including input prices) and financing costs. The nature of the BSIS scheme, where many elements that define the Incentivised Balancing Cost (IBC) target are agreed upfront (and the eight year length of the control) will mean that the certainty associated with forecasts vastly reduces over time. As a result, there is a risk that:

(a) The revenues raised from consumers could be higher or lower than necessary to cover the costs of providing SO services, with consumers paying more or less for services than was necessary; and

(b) The incentivised areas are set at the time of the control may turn out to be insufficient or inappropriate.

622 Therefore, the main sources of uncertainty surrounding the SO incentives relate to the delivery of outputs, the input prices, volumes of activity required and changes to the political and regulatory operational background. As part of the RIIO-T1 framework, Ofgem has proposed three main options to deal with this uncertainty, namely:

(a) Risk sharing through the efficiency incentive rate

(b) Uncertainty mechanisms; and

(c) A mid-period review of the output requirements.

623 Within the RIIO framework Ofgem has stated that they expect the SO to be exposed to risk emanating from uncertainties that the SO can meaningfully manage, influence or otherwise mitigate and that they expect the SO to bear its own business risk. We should manage the uncertainty we face, in order to ensure the most efficient outcome for consumers.

624 As part of the specific incentive design, we have included a number of mechanisms that allow for incentive longevity, including model adjustment mechanisms and ex post volume adjusters. Risk has been further managed through the scheme parameters in terms of scheme length, sharing factors and caps / collars.

625 Irrespective of this however, an element of residual risk remains. We have therefore undertaken an exercise to better understand the financial risks that we will face from our SO external activities over the forthcoming RIIO-T1 price control period. The risk that we face from our system operation role determines the return on equity we require. This required equity premium can then be converted into an annual £7.7m premium to cover the residual risk. We have not, as part of this submission, specified a means by which this premium should be remunerated.

Key drivers of risk and uncertainty

626 As described in greater detail within the 'System Operator Role: Now and into the future' section of this document, the operating environment is set to fundamentally change over the RIIO-T1 period, principally driven by the changes required to meet the UK's 2020 environmental targets. The shift towards a lower carbon economy and its corresponding affect on the generation and demand background, transmission network design and market frameworks manifest itself in fundamentally increasing the operational risk that we face as the NETSO.

627 These changes can be broadly captured within four categories:

(a) **Price risk:** The market price at which we can access the balancing mechanism and procure ancillary services is principally driven by two factors: fuel input costs and capacity limitations. The fuel input cost is determined by international markets and as the decade progresses the price of carbon will become more important. Capacity limitations of the generation fleet (including interconnector and demand turn down capacity) will also drive future price uncertainty. With the churn in the generation portfolio during the RIIO-T1 period and an increasing reliance on the importation of primary fuel input sources, we will face considerable price uncertainty in undertaking our NETSO responsibilities;

(b) **Volume risk:** As the residual balancer we face uncertainty around the volume of actions that we will need to take. This is driven by various factors that are directly or indirectly out with our control such as demand and supply mismatches and the volume of constraints on the system that we need to resolve. Changes to the generation portfolio and the way industry parties manage demand, coupled with greater interconnection with Europe, will culminate in increasing variability of the volume of actions we need to undertake;

(c) **Political / Regulatory risk:** In order to meet carbon reduction targets, both on a UK and European wide level, considerable uncertainty is introduced through the required changes to market frameworks. For example reviews such as Electricity Market Reform, Project TransmiT and European Network Code developments, all carry considerable risk to the way that we operate. Political risk also gives rise to increasing uncertainty. A clear example of such a risk was the decision by Germany to close its nuclear plants by 2022 and immediately closing several of its oldest plants following the Fukushima disaster; and

(d) **Operating environment:** Managing the cost of one off events such as floods and storms gives rise to further levels of uncertainty and risk.

628 Whilst not an exhaustive list, these types of risks need to be factored into the potential total range of external costs that we may incur in carrying out our SO role. The remainder of this section describes how we have factored these risks into our initial modelling and how we will require uncertainty mechanisms to cover specific risks.

Risk analysis process

629 In order to be able to assess the risks that may impact the achievement of our business objectives, it is essential for us to be able to understand them. This knowledge will allow us to make better decisions, deliver strategic and operational performance targets, protect corporate reputation and ensure value for money for customers and other stakeholders.

630 In assessing our risk management approach we have been guided by the Turnbull Guidance (Revised Turnbull Guidance, para 4, October 2005):

'A company's objectives, its internal organisation and the environment in which it operates are continually evolving and, as a result, the risks (operational, financial, compliance and other) it faces are continually changing. A sound system of internal control therefore depends on a thorough and regular evaluation of the nature and extent of the risks to which the company is exposed. Since profits are, in part, the reward for successful risk-taking in business, the purpose of internal control is to help manage and control risk appropriately rather than to eliminate it.'

631 In response to Turnbull and other best practice guidance, we use two separate but complementary processes: Risk Management and Compliance Management. These have been designed primarily as management tools but they also:

(a) contribute toward a better informed decision making process to help businesses achieve their objectives;

(b) strengthen and streamline the system of internal control;

(c) support and reinforce an open, proactive and 'risk and compliance aware' work culture;

(d) closely align to business planning, performance management, and internal audit planning;

(e) contribute toward a relevant and cost effective insurance programme;

(f) facilitate the identification of opportunities (upside) as well as risks (downside);

(g) help protect reputation and shareholder value;

(h) enable us to clearly demonstrate good corporate governance to its stakeholders; and

(i) ensure compliance with the listing requirements of the London Stock Exchange.

632 The price control review provides an opportunity for us to review our risk appetite. The regulatory arrangements that will be put in place for the RIIO-T1 period will inevitably depart from those in place today under the TPCR4

framework. The changes have the potential to fundamentally alter the risks to which the business is exposed and, therefore, the risks that customers and other stakeholders might be asked to bear. Given the potential impact of these changes it is right for us to revisit the fundamental risk drivers for our SO business, in order to understand the nature of these risks and their potential materiality.

633 In certain instances it might be suitable for us to bear more risk going forward into the RIIO-T1 period than it was previously in TPCR4, provided that this increase in risk is reflected in the setting of SO incentive schemes. In addition, the prospect of regulatory framework change means that risk will increase in a number of areas where there is little we can do to manage it. This creates the need for new uncertainty mechanisms, or the enhancement of existing uncertainty mechanisms.

634 There are some risks that are completely (or largely) beyond our control, or where the only available actions are prohibitively expensive and clearly would not provide value. In such cases it is not clear that it is in consumers' best interests for us to bear those risks (and act as an insurer earning a premium) or whether the consequence of these uncertainties would be more efficiently passed through to customers. This principle has formed the basis of our analysis on the modelling of IBC target costs and which model inputs should be treated as Ex Ante or Ex Post. We have based our analysis on the principle that risks should fall on those parties best able to manage them.

635 It may be in the consumers' best interests to be exposed to particular risks where this brings value by, for example:

(a) Lowering our allowed rate of return;

(b) Reducing financeability concerns; and/or

(c) Reducing consumers' exposure to forecasting uncertainty at the price control review.

636 Where we believe that there are good arguments for risks to fall on end consumers, we have initially described potential areas for uncertainty mechanisms. As we finalise the structure of the cost models to use in forecasting IBC target costs we will need to further explore how the use of uncertainty mechanisms (above and beyond the Ex Ante, Ex Post methodology) can be best used to share the inherent risk of an eight year SO incentive scheme.

637 For those risks which can be managed by system users, we will continue to pursue developments to the commercial regime to better reflect risks to those system users that cause them, such that they are able to make more efficient decisions.

638 To support our risk analysis work for RIIO-T1, we have developed a risk model to better understand the relationship between risks, a proxy for uncertainty mechanisms (whilst we develop our longer term IBC models) and our financial performance. The model uses probabilistic techniques to evaluate the impact on financial performance for the RIIO-T1 price control which builds on the analysis undertaken for our Transmission Operator

submission. This provides a basis for assessing the impact of System Operator risks.

Risk Modelling

639 In designing the scheme and exploring what the appropriate boundary is between who should manage the risk (either us or the consumer), we have begun initially modelling what the potential range of total IBC costs could be for the eight year period.

640 To understand the likely range of IBC costs we have undertaken a scenario based approach to calculate the range of potential scheme cost outturns. As described in the March RIIO-T1 submission in 'The future of energy' Annex, we have again utilised the 'Gone Green' scenario. This scenario builds upon initial work undertaken through the Electricity Networks Strategy Group (ENSG) in 2009 to produce a potential mix of transmission-connected generation out to 2020.

641 In recognition that there is inherent uncertainty in forecasting, the Gone Green scenario is supplemented by two other scenarios – slow progression and accelerated growth, which have similarly been peer reviewed and supported by the industry.

It was widely felt that the three scenarios…..represented a reasonable range of possibilities and that they are all plausible….Gone Green was the overall favoured scenario and the best approximation of what is likely to happen.

Stage two workshop Brunswick report, 31st March 2011

642 These three scenarios have been supplemented for modelling purposes with four other scenarios which are variants of the three central scenarios. Whilst these scenarios broadly capture the effect of changing generation and demand scenarios, they also look to capture the cost of other events materialising such as increasing European interactions, greater unplanned faults on the system and delays to delivery of major infrastructure enhancements. Below is a brief description of the seven different cost scenarios that were created:

(a) **Gone Green:** This scenario represents a potential generation and demand background which meets the UK's 2020 environmental targets and maintains the country's progress towards meeting its 2050 emissions targets. The costs associated with this scenario are underpinned by the work undertaken within our 'Operating the Electricity Transmission networks in 2020' consultation[65];

(b) **Slow Progression:** In this scenario, the emphasis is on slower than planned progress towards the UK's 2020 environmental targets. This scenario has been developed against a background of lower carbon

[65] http://www.nationalgrid.com/uk/Electricity/Operating+in+2020/

prices resulting in a slower build-up of lower carbon generation and a greater reliance on gas-fired plant;

(c) **Accelerated Growth:** The accelerated growth scenario uses the Gone Green onshore generation background as a base, with the assumption that offshore generation builds up far more quickly and that 2020 renewable targets are met ahead of schedule under this scenario;

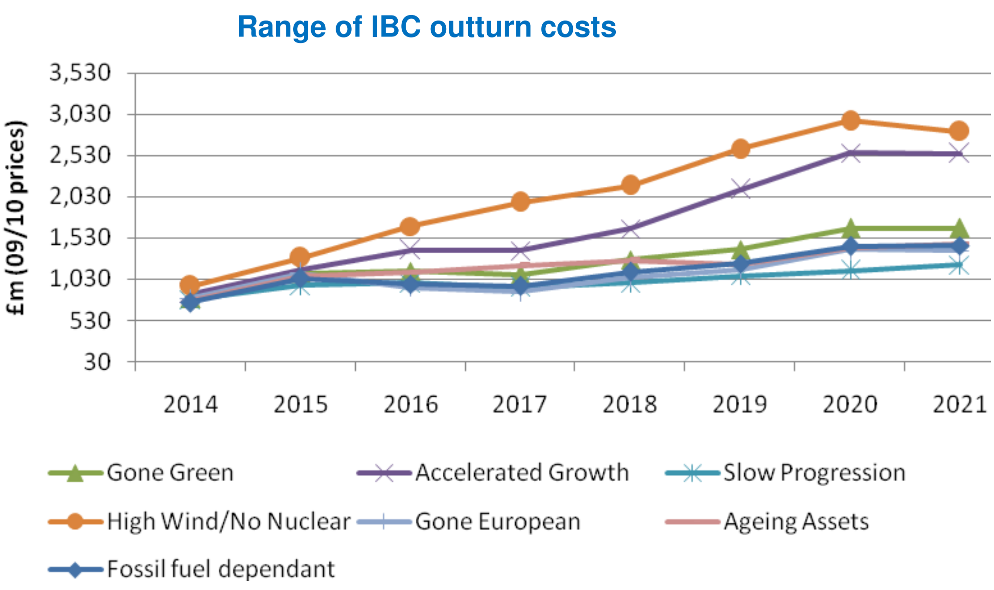
(d) **High Wind / No Nuclear:** Scenario assumes that similar to Germany, there is a complete withdrawal of nuclear generation. Instead, the shortfall is provided from increased wind generation and greater reliance on gas fired generation. The scenario also assumes a delay in the completion of the Western HVDC link between Scotland and England;

(e) **Gone European:** Similar generation background to Gone Green apart from the total volume of Interconnector capacity to the UK increases to 12GW by the end of the RIIO-T1 period. This assumes that there is a slight fall in the volume of gas generation;

(f) **Ageing Assets:** This scenario is dominated by the proliferation of gas generation. It assumes that there is a reduction in nuclear generation as ageing plants have to be decommissioned earlier than expected. The scenario also assumes that the IFA interconnector permanently fails and that there are increasing faults around the network; and

(g) **Fossil Fuel Dependent:** This scenario assumes a high proliferation of gas generation and that designated LCPD plant are allowed to generate post 2015. It also assumes that finance is readily available and that transmission and generation capacity is delivered ahead of time.

643 Utilising this broad scenario based approach; a potential range of IBC cost outturns has been calculated for each scenario on an annual basis. The graph below depicts the spread of these costs.



644 Whilst the detailed IBC models continue to be developed this high level modelling approach provides an insight into the financial implications of risks and uncertainties. This high level approach is not intended to define the actual risk and sharing of risks.

Modelled IBC cost range methodology

645 We have used the likely IBC cost ranges from the seven scenarios to set the variables for risk modelling. The arithmetic mean of the scenarios has been used to determine the target, assuming 50% of the forecast deviation will be adjusted through an ex-post input. This is akin to the existing incentive arrangements where the target is determined with a combination of ex-ante and ex-post adjustments. The actual proportion of the ex-ante/ex-post adjustment may vary year-on-year, however we believe this provides a reasonable basis for the purposes of risk modelling.

646 We have then assigned a probability to each of the cost categories and undertaken a Monte-Carlo simulation to create a discrete distribution for each of the categories of cost.

647 The modelled IBC costs over the RIIO-T1 period ranges from £9.1bn to £14.0bn, and thus an appropriate incentive mechanism is pertinent to ensure that together with our stakeholders we are not exposed to financial distress. The table below illustrates the range of potential outcomes over the RIIO-T1 period.

Range of potential outcomes to IBC over the RIIO-T1 period

	Overall IBC cost ranges (09/10 prices)								
	2014	2015	2016	2017	2018	2019	2020	2021	Total over RIIO-T1 period
Std. Dev.	32	46	117	184	191	263	291	242	550
Mean	815	1,102	1,169	1,197	1,354	1,536	1,786	1,785	10,745
Min	695	956	842	848	898	979	1,138	1,172	9,052
Max	930	1,319	2,151	3,644	2,868	4,776	4,964	3,907	13,983
2.50%	754	1,017	973	964	1,081	1,180	1,358	1,396	9,804
97.50%	879	1,198	1,426	1,635	1,831	2,202	2,477	2,333	11,954

648 The table below summarises the individual cost categories that are considered in modelling the risk and scales of the uncertainties for the total IBC cost.

Individual IBC cost categories

Category	Standard deviation (£m over the RIIO-T1 period)
Margin	250
Frequency Response	124
Fast reserve	43
Foot room	13
Reactive Power	1
Constraints	475
Unclassified BM	0
Black start	9
Total IBC costs	550

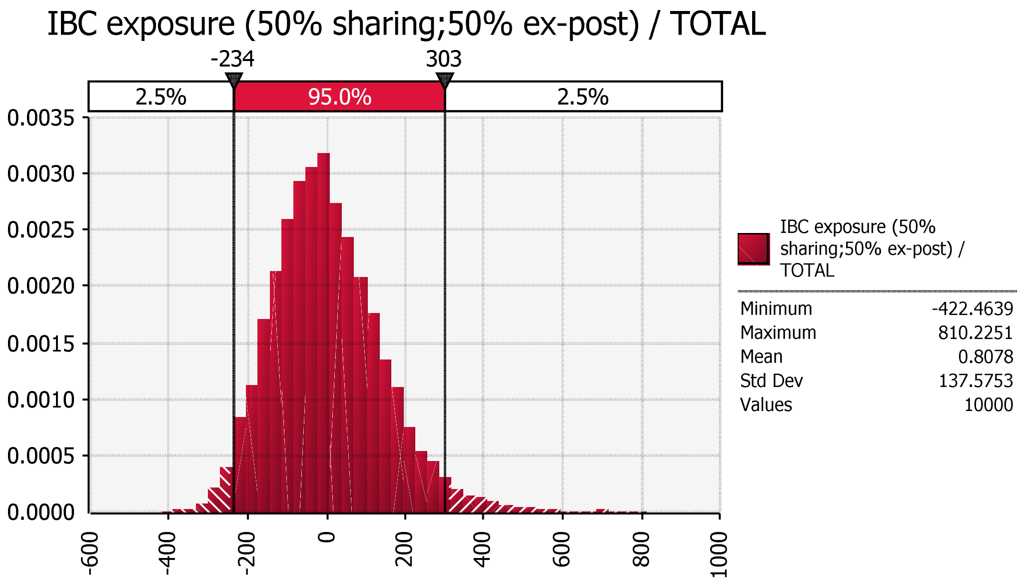
649 As depicted the cost of managing system constraints is the single largest factor in determining the overall level of risk, reflecting the considerable change to the generation landscape over the RIIO-T1 period and the requirement for system access to facilitate the capital plans of the TOs.

650 Whilst the analysis described above provides a range of costs for the RIIO-T1 period it does not delineate how the risk exposure is being shared between the end consumer and ourselves. To do so, we need to understand the likely performance against a target price. The risk that we have historically been exposed to is the forecasting risk between the target price (normalised for dead band) and the actual outturn of schemes.

Targets and Performance

651 The range of overall cost exposure assuming 50% of any deviation from target cost is covered through an ex-post adjustment, before the application of sharing factors and caps/collars, ranges between -£0.8bn (below target) and £1.6bn (above target) with a standard deviation of £275m over the RIIO-T1 period.

652 The application of a 50% sharing factor reduces the exposure as illustrated by the chart below.



653 Although the exposure would be reduced it still requires us to have a balance sheet to be able to finance a potential range of costs between -£0.4bn (below target) and £0.8bn (above target) with a standard deviation of £138m over the RIIO-T1 period. This also exposes our customers to increased level of uncertainty from windfall gains and losses. The table below summaries the expected outcome over the RIIO-T1 period.

IBC exposure, (2009/10 prices) without caps/collars

	50% sharing factors and no caps/collars								
	2014	2015	2016	2017	2018	2019	2020	2021	Total over RIIO-T1 period[66]
Std. Dev.	8	12	29	46	48	66	73	60	138
Mean	0	0	0	1	(0)	(0)	(1)	0	1
Min	(30)	(36)	(82)	(86)	(114)	(140)	(162)	(153)	(422)
Max	29	54	246	613	378	810	794	531	810
2.50%	(15)	(21)	(49)	(57)	(68)	(89)	(108)	(97)	(234)
97.50%	16	24	64	111	119	166	172	137	303

654 The table above also shows that without caps/collars the risk is asymmetric, meaning that there is more downside within the scheme than upside, as shown by the potential to lose up to £800m in several years of the RIIO-T1

[66] Total over the period will not equate to the sum of individual years' statistics as each year has been separately calculated for each simulation run.

control period, but only the opportunity to receive a maximum incentive profit remaining well below £200m.

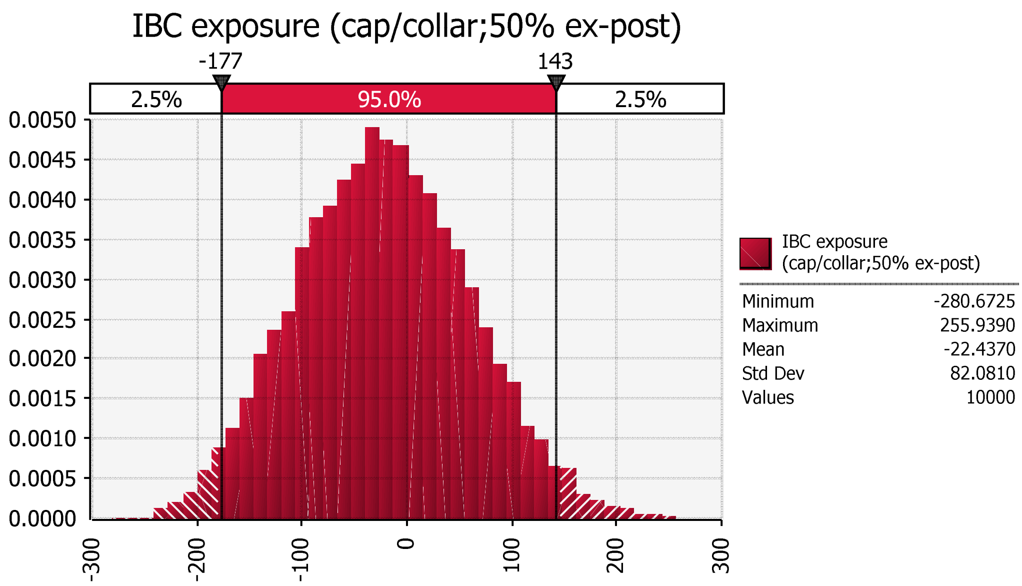
655 We have proposed that we continue to apply caps/collars as described within the ‘BSIS Scheme Design and Governance’ section of this document, in such a way as to protect consumers and ourselves from windfall gains and losses and present a fair balance of risk and reward. We believe the use of caps/collars under the RIIO-T1 regime should evolve as we together with our stakeholders gain confidence in the new models and methodologies used in setting targets. To this end we have proposed a cap/collar and sharing factor which widens over time from +/-£30m & 30% to +/-£50m & 50%. The table below summaries the proposed caps/collars and sharing factors and how these widen over time.

Proposed BSIS parameters

	Annual scheme parameters							
	2014	2015	2016	2017	2018	2019	2020	2021
Collar (£m)	-30	-30	-40	-40	-50	-50	-50	-50
Cap (£m)	30	30	40	40	50	50	50	50
Sharing factors	30%	30%	40%	40%	50%	50%	50%	50%

656 By introducing variable cap/collar and sharing factors, the overall level of exposure is reduced, whilst still providing us with a level of incentive to review and refine the models/methodology and find innovative ways to deliver value to end consumers by minimising system operation costs.

657 The chart below illustrates the reduced range of costs between -£281m (below target) and £256m (above target) over the RIIO-T1 period. This provides protection to our customers from uncertainty of windfall gains and losses.



IBC exposure with proposed BSIS parameters (2009/10 prices)

	sharing factors 30% to 50% with £30m to £50m cap/collar								
	2014	2015	2016	2017	2018	2019	2020	2021	Total over RIIO-T1 period
Std. Dev.	5	7	21	24	33	37	39	38	82
Mean	0	0	(1)	(3)	(4)	(6)	(6)	(3)	(22)
Min	(18)	(22)	(40)	(40)	(50)	(50)	(50)	(50)	(281)
Max	17	30	40	40	50	50	50	50	256
2.50%	(9)	(13)	(39)	(40)	(50)	(50)	(50)	(50)	(177)
97.50%	10	14	40	40	50	50	50	50	143

658 The widening cap/collar provides us the opportunity to gain confidence and yet at the same time protect our customers from increased volatility whilst the new models/methodologies are embedded.

Financeability

659 As noted within paragraphs 399 to 403 of the 'NGET Finance' Annex of our March submission, consideration of the risks that we face within our SO business need to be appropriately accounted for. We noted that return on equity for the SO business on a standalone basis is inadequate (due to the size of the SO Regulatory Asset Value and we stated that there were two alternatives which could be considered:

(a) Provide for a net positive expected incentive outcome in the SO control; and

(b) Allow a premium to the TO cost of equity.

660 We do not believe that providing additional return via the TO control itself is an appropriate solution as this could result in a cross-subsidy between different classes of user. This is, however, an appropriate way of determining a value for the risk premium which the SO should receive, commensurate with the level of risks from the application of the SO incentive scheme.

Risk premium

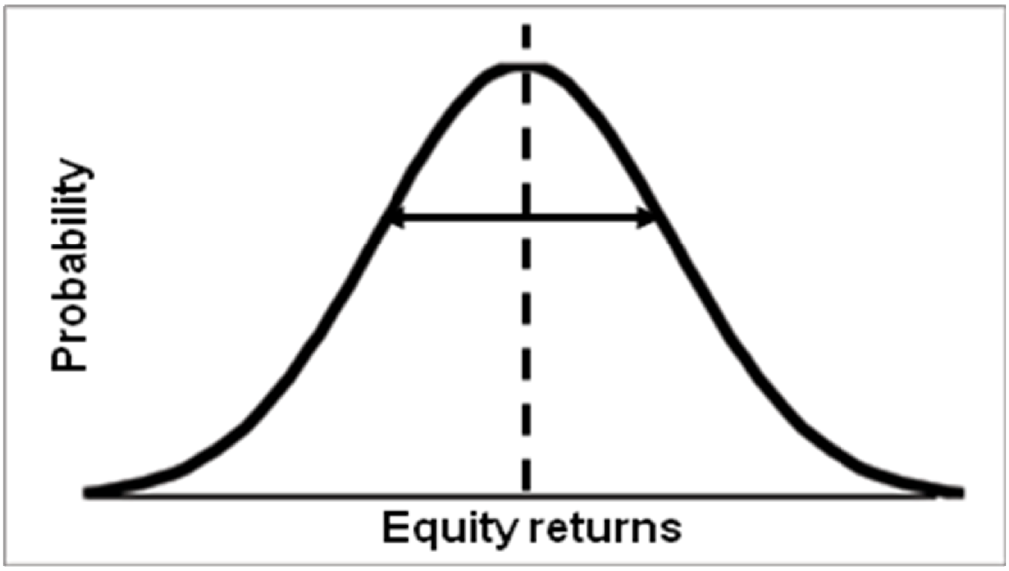
661 A distinction needs to be made between reward for performance and remuneration for undertaking risk. The incentive outcome provides an opportunity for us to be rewarded for good performance and penalised for bad performance.

662 However an incentive mechanism itself does not provide any remuneration for undertaking and managing risks. The concept of risk and reward trade-off is an accepted part of finance theory which we described within paragraphs 259

to 308 of our 'NGET Finance' annex of our March submission. We are proposing that a premium for undertaking and managing the risk associated with the SO incentives is included within the incentive package.

663 Risk can be defined as the variation in asset returns around expected asset returns, i.e. it is a measure of volatility. The Sharpe ratio can be used to compare two portfolios with different degrees of volatility to assess whether the risk-return trade off is appropriate. Within the March submission, we investigated the relationship between the required return on equity and variation in equity returns. We propose to use the same approach to determine the appropriate premium for the risks posed by the various SO incentive schemes.

664 In translating the risk to an equity return our modelling considered the dispersion in equity returns for different incentivisation methods described above (with or without caps/collars). The narrower the dispersion in equity returns, the lower the justified premium over risk free rates. Dispersion is illustrated in the diagram below.



665 As NETSO, we do not have a sufficiently large balance sheet to finance or absorb the risk associated with the levels of cash flow requirement described above. These risks would effectively be underwritten by the wider National Grid balance sheet, and thus we have derived the return that would be appropriate as an increment to the required NGET TO return using the Sharpe ratio. Assuming the risk free rate to be constant, the risk/return balance is maintained if:

$$\frac{Return_{TO} - Return_{Risk\ free}}{\sigma_{TO}} = \frac{Return_{TO+SO} - Return_{Risk\ free}}{\sigma_{TO+SO}}$$

Where σ represents the standard deviation of returns.

666 Our March submission explains why the appropriate return for our TO business, and its associated risk profile is 7.5%. We have performed additional modelling to add the SO risk to establish the incremental impact. The table below summaries the impact on the required post-tax cost of equity with the application of the Sharpe ratio.

Incremental change in required return			
	Standard deviation of pre-tax return on equity	Implied post tax cost of equity	Incremental return
Base case (RIIO TO submission)	0.5848%	7.50%	-
50% sharing factor & no caps/collars	0.6263%	7.89%	0.39%
Variable sharing factor & caps/collars	0.5991%	7.64%	0.14%

667 An increment of 39 basis points to the TO equity return is required to undertake the potential level of SO risk without any caps/collars. When caps/collars and variable sharing factors are introduced the requirement drops to 14 basis points.

668 The NETSO Regulatory Asset Value (RAV) is very small and thus a rate of return cannot be credibly set that could be applied to the RAV. As a result the potential premium was calculated using the NGET RAV. The average opening RAV for the NGET over the RIIO-T1 period is £12.7bn. Assuming a gearing level of 55%, this implies that the equity portion of this is £5.7bn.

669 Therefore we can use each of the additional implied post tax cost of equity figures calculated in the table above to derive an appropriate annual risk premium, by multiplying them by the assumed equity portion of the RAV. The results are shown in the table below:

Annual risk premium

Scheme considered	Resultant annual risk premium (£m)
50% sharing factor & no caps/collars	22.2
Variable sharing factor & caps/collars	7.7

670 Considering the premium requirement for an incentive mechanism with a 50% sharing factor without the application of caps/collar the annual premium should be approximately £22.2m per annum. With the application of caps/collars as proposed, the expected premium reduces to approximately £7.7m per annum.

Sense check

671 As a sense check to the proposed risk premium, we have sought to identify the level of risk premium investors might expect if the SO were a stand-alone business, given the risk they would face underwriting the SO incentive schemes.

672 A standalone SO business carrying the risk proposed would need a balance sheet to absorb that risk. A balance sheet size of 3 years worth of losses appears reasonable.

673 The 95% confidence interval for annual scheme performance shows an average lower limit of around £101m for a sharing factor only scheme and £38m for a scheme with caps / collars.

674 Under a scheme without caps / collars the expected loss over three years amounts to £303m (£101m x 3) and £114m for a scheme with caps / collars. The table below shows the expected equity financing requirements using varying equity returns.

IBC scheme performance (2009/10 prices)

	Annual Scheme Performance - 95% confidence interval (lower limit)								
	2014 £m	2015 £m	2016 £m	2017 £m	2018 £m	2019 £m	2020 £m	2021 £m	Average over RIIO-T1 period £m
50% sharing factor	16	24	64	111	119	166	172	137	**101**
Widening sharing factor & caps/collars	10	14	40	40	50	50	50	50	**38**

675 Given the scale of risks, such a business would need to be wholly equity funded. Equally, such a business would be expected to have a cost of equity higher than that of the TO business, predicated by the fact that the SO business balance sheet does not have the capability to absorb these risks.

676 We have used a range of equity return to illustrate the potential risk premium requirements to attract equity investors. The table below shows the expected equity financing requirements using varying equity returns.

Equity risk premium requirements for a standalone SO

Risk premium based on 3 years of average losses		
Rate of equity return	**50% sharing factor (£m)**	**Variable sharing factor & caps/collars (£m)**
7.5%	22.7	8.6
10%	30.3	11.4
12%	36.4	13.7

677 Compared to the proposed 7.5% return on equity for our NGET business, the SO as a stand-alone business would be substantially more risky and thus would command a correspondingly higher rate of return. Investors in a stand-alone SO would expect a return of at least 10%, giving an expected annual risk premium in the range £11.4m and £36.4m from the table above, dependant on the incentive scheme parameters.

678 We have proposed a risk premium of £7.7m per annum (in 09/10 prices) which is lower than what would be required for a stand-alone SO business due to the benefits of risk diversification across our wide transmission business.

Funding the additional risk premium

679 Whilst the return on equity approach for the SO business on a standalone basis is inappropriate (due to the size of the SO RAV), the risk premium required to cover the residual risk of the SO incentives could be managed in one of three ways:

(a) A risk premium allowance in the SO control

(b) An explicit administration fee; or

(c) Additional return via the TO control

680 We do not believe that providing additional return via the TO control itself is appropriate as this could result in a cross-subsidy between different classes of user. We propose that the risk premium is included as a risk premium as part of the SO incentive scheme package.

Funding the additional risk premium

681 Whilst the return on equity approach for the SO business on a standalone basis is inappropriate (due to the size of the SO RAV), the reward required to cover residual risk could be managed in one of three ways:

(a) Provide for a net positive expected incentive outcome in the SO control;

(b) An explicit administration fee; or

(c) Additional return via the TO control.

682 We do not believe that providing additional return via the TO control itself is an appropriate solution as this could result in a cross-subsidy between different classes of user. The means by which the additional premium is remunerated will need careful consideration when determining the overall SO package of incentives.

Uncertainty Mechanisms

683 The GB electricity market is facing a period of significant change and uncertainty with the development of a sustainable, low carbon electricity sector and greater market integration with Europe. Setting a robust and effective long-term incentive scheme against this level of uncertainty is going to be extremely difficult, and can only be achieved if they are supported by a range of uncertainty mechanisms.

684 The proposed incentive schemes set out in this submission have been designed to deal with a degree of uncertainty using mechanisms that adjust the incentive target based on factors outside of our control. Caps and collars are also proposed to protect against windfall gains or losses resulting from issues not captured by these mechanisms. We also propose to retain the concept of Income Adjusting Events (IAEs) to deal with major events outside our control. Combined, these will help protect consumers and ourselves from windfall gains and losses.

685 For the BSIS scheme, we have proposed that caps and collars are widened as we gain confidence in the ability of the target model to provide an accurate cost against which the efficiency of our activities can be judged.

686 For the Renewable Forecasting incentive schemes, we also propose the use of a cap and collar to limit exposure to unforeseen events, and that the methodology used to calculate an annual target is reviewed after four years.

687 There are a number of wider developments to the Electricity sector which could have a major impact on the operation of the Balancing Services incentive scheme. These are Electricity Market Reform (EMR), Project TransmiT, the Significant Code Review on market imbalance cash-out arrangements, and European developments.

Electricity Market Reform (EMR)

688 In July 2011, the Government published its Electricity Market Reform White Paper[67] which set out its commitment to transform the electricity market in Great Britain to ensure that our future electricity supply is secure, low-carbon and affordable. The project aims to assess the role that a package of incentives could play in supporting the delivery of low carbon generation and security of supply for 2020 and beyond. The objective is to encourage timely investment in all low carbon generation technologies while maintaining

[67] http://www.decc.gov.uk/en/content/cms/legislation/white_papers/emr_wp_2011/emr_wp_2011.aspx

security of supply. The transmission network is expected to play a vital role in ensuring these wider energy market objectives are successfully met.

689 EMR could fundamentally alter the economic principles which underpin the current operation of the electricity market, and as such, the incentive scheme should be revisited when EMR is introduced.

Project TransmiT

690 Alongside the government's EMR proposals, Ofgem is conducting an independent and open review of the transmission charging and connection arrangements through Project TransmiT. Its aim is to ensure that arrangements are in place which will facilitate the timely move to a low carbon energy sector whilst continuing to provide safe, secure, high quality network services at value for money to existing and future consumers. Electricity transmission charging is one of the immediate priorities for Project TransmiT with Ofgem announcing in July 2011 the launch of a Significant Code Review (SCR). The SCR is focusing on options for potential changes to the existing Transmission Network Use of System (TNUoS) charging arrangements, user commitment and reporting obligations.

691 These reforms are likely to see changes in transmission access charges, thus modifying behaviours in the citing of new generation plant and the economics of running existing plant. These in turn are likely to impact on the costs incurred under the BSIS scheme and the level of Transmission Losses experienced. As such, the impact on the incentive schemes should be reviewed when these reforms are introduced.

Electricity Cash-Out Review

692 In March 2012, Ofgem launched a Significant Code Review of electricity market cash-out arrangements, looking to sharpen incentives on balancing to improve security of supply and reduce balancing costs, both of which should benefit consumers. Again, this is likely to impact on our role in balancing the transmission system and the associated costs we incur, and it would seem appropriate to review the BSIS scheme when any reforms are introduced in this area.

Europe

693 Over the RIIO-T1 period, we expect Europe to continue to influence the UK electricity supply industry through the development of European Network Codes and proposed European legislation. The wider European market could influence the operation of new and existing interconnectors, transmission access and charging rules, and energy balancing rules.

694 Our investment plan assumes the connection of new interconnectors to France (IFA2), Belgium (NEMO) and Norway in the RIIO-T1 period to provide a total interconnection capacity of 7.5GW from Great Britain, or over 10% of the forecast maximum demand. Therefore as our Electricity system becomes part of a wider European network, both physically and in terms of the market framework in which we operate, the BSIS incentive arrangements could radically change.

Income Adjusting Events

695 Income Adjusting Events provide a further uncertainty mechanism to deal with significant and unexpected events or circumstances outside our control, where funding for these events or circumstances was not included in setting the allowed revenues under the incentive schemes.

696 Ofgem has a duty to ensure that licence holders are able to finance the activities which are the subject of obligations on them, and the IAE provisions provide an important safeguard to ensure that obligations can be funded in light of events or circumstances not envisaged when revenue allowances were set.

697 At present, an income adjusting event in relation to external NETSO costs can be any of the following:

(a) An event or circumstance constituting force majeure under the BSC;

(b) An event or circumstance constituting force majeure under the CUSC;

(c) A security period; and

(d) An event or circumstance which Ofgem approves as an income adjusting event where the impact on balancing services costs is in excess of £2m.

698 As an example, following the introduction of BETTA in 2005, constraint volumes in Scotland and across the Anglo-Scottish Interconnector were significantly higher than were allowed in setting the GBSO's allowed revenues. Ofgem subsequently approved an adjustment to account for these unforeseen costs. Without this adjustment, the NETSO would not have been able to finance the cost of securing the transmission network in Scotland in 2005/06.

699 This can work both ways – to the extent that costs are allowed in the incentive scheme, based on events or circumstances that do not materialise, it would be inappropriate for NGET to make windfall gains at the expense of consumers as a result.

700 A good example occurred during 2009, where revenue allowances under BSIS assumed the closure of a major demand side response provider. Had this provider remained open, we would have benefitted from a substantial windfall gain in the order of £15m – however, we flagged this to Ofgem as a potential IAE to ensure no such windfall gain would occur, therefore ensuring consumer interests would be protected had the DSR provider remained open.

701 A second related example occurred in 2010 in relation to the NETSO's internal cost allowances, where we raised an outage cost adjusting event to reduce the £1m annual allowances we receive to cover payments to the other transmission owners to reschedule transmission outages in Scotland to reduce the costs of balancing the system. Payments incurred were historically much lower than the allowance provided, and Ofgem approved the adjustment, accordingly reducing the NETSO's allowed revenues.

702 Furthermore, other BSC and CUSC parties can also raise IAEs if they consider that events or circumstances have occurred that result in costs being less than expected at the time the incentive scheme revenue was set. The two-way nature of the IAE provisions represents an important safeguard to the industry and consumers alike.

703 These provisions have been a fundamental part of the incentive framework for many years. They are rarely used, and therefore represent a low overhead to maintain, but represent an important mechanism to ensure that obligations with regard to system operator activities can be funded in light of significant unexpected events or circumstances not envisaged when revenue allowances were set. These provisions also allow for the incentive properties of the schemes to be maintained following such events.

704 Given the intention to move towards longer-term scheme, in which the range of uncertainty becomes much broader due to the length of the schemes and the fundamental changes we expect to see across the UK energy sector over this period, we believe it imperative that this form of uncertainty mechanism is retained. This will help to ensure that the NETSO continues to be subject to a fair, credible and transparent incentive framework.

705 As part of our package of proposals for NETSO incentives under RIIO-T1, we therefore propose the continued application of Income Adjusting Events (IAEs) at the current £2m threshold.

Summary

706 Through the proposed scheme design, we have set out to ensure risk is placed on those parties best able to manage them. The use of an ex ante / ex post determination of modelling inputs, sharing factors, caps / collars and the proposed uncertainty mechanisms all contribute towards this objective. Combined, they aim to protect consumers and ourselves from windfall gains and losses whilst incentivising the most appropriate management actions.

Charging

Overview

707 The Balancing Services Use of System (BSUoS) charge is the charge through which we recover the costs of our NETSO activities. Stakeholders have highlighted the importance of stable and predictable charges as they affect their forward planning, including tariffs for consumer bills.

708 This section sets out how changes in BSUoS charges are driven by the BSIS incentive performance and other elements such as industry driven changes.

709 The incentive performance constitutes a small proportion of the total BSUoS charge and therefore has a limited impact on charges. We set out proposed mechanisms that aim to reduce volatility in the incentive performance and hence customer charges.

What is BSUoS

710 BSUoS charges cover the costs associated with operating the NETS and the procurement and utilisation of Balancing Services. All CUSC Parties are liable for BSUoS charges, based on their energy taken from or supplied to the NETS in each half-hour settlement period

711 BSUoS charges comprise the following costs:

(a) Total costs of the Balancing Mechanism;

(b) Costs associated with developing and contracting for Balancing Services;

(c) Total Balancing Service contract costs;

(d) Payments/receipts from National Grid incentive schemes; and

(e) Internal costs[68] of the NETSO function e.g. salaries, facilities etc.

712 BSUoS charges seek to recover period specific costs and are therefore calculated and invoiced daily for each half hourly settlement period. Each customer's charge is based on their proportion of BM Unit metered volume relative to the total BM Unit metered volume for each settlement period and adjusted for Transmission Losses.

How it is calculated and charged

713 The total BSUoS charges for each settlement period are calculated by summing the external and internal BSUoS charge.

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[68] As described in our March Detailed Plan – System Operation annex

714 The external BSUoS charges for each settlement period (BSUoSEXT) are calculated by taking System Operator BM Cash Flow and Balancing Service Variable Contract Cost; and allocating the daily elements on a MWh basis across each Settlement Period in a day:

BSUoSEXT = CSOBM + BSCCV + {IncpayEXT + profiling factors}

Where:

CSOBM *= System Operator BM Cash Flow*

BSCCV *= Balancing Service Variable Contract Cost*

IncpayEXT *= the difference between the new total BSIS payment and the payment that has been made from the commencement of the scheme*

Profiling factors *= included to give an effective mechanism for calculating a representative level of the incentive payments according to the time of year*

715 BSUoS charging is currently subject to a two stage financial settlement over a period of 14 months. The two billable settlement runs are:

(a) Settlement Final – performed on Settlement Day plus 16 working days. Invoices are issued and payment is required on the payment day; and

(b) Reconciliation Final - reconciliation 14 months after settlement day to account for actual cost and metering information.

716 Reconciliations are carried out to account for differences between the most recent customer charge and what has been charged and settled to date through previous runs.

717 The current BSIS framework operates on the basis that models and datasets, rather than a forecast of incentivised costs, are agreed for the purposes of setting the incentive scheme. However a forecast of the BSIS performance value is calculated daily, using a rolling average for the incentive period and included into the BSUoS calculation system.

718 As the scheme progress and more actual cost data is accumulated, the target cost and performance figure becomes more accurate. The BSUoS charge is therefore reconciled to account for differences in actual incentive payments and those already charged to customers.

Within Scheme changes

719 As part of our stakeholder engagement process, our customers highlighted the importance of stable charges, and if not stable, then at least predictable. This was seen as vital as BSUoS charges affect their forward planning, including tariffs for consumer bills. The realisation of the BSIS payment to be included in charge calculation at the end of the scheme period was seen as a driver of uncertainty in charges.

''Predictability and transparency go hand in hand, so we can forecast future charges and transparency so everyone in the market has the same view about what charges are.''
Supplier comment, November 2011 RIIO-T1 charging workshop

720 The BSIS performance element constitutes a small proportion of BSUoS charges, accounting for approximately 2%[69] of the total BSUoS revenue collected. Any changes in BSIS will therefore give rise to a limited amount of volatility in charges.

721 Other elements of the BSUoS charge that can also cause volatility form part of the BSUoS charging methodology. This methodology is now contained in the Connection and Use of System Code[70] (the CUSC) and therefore subject to open governance arrangements. Hence these are continuously open to industry discussion and proposal; some examples are provided in the section below.

722 To increase transparency and give customers and the industry an indication of costs from the BSIS, we provide a BSUoS charge forecast as part of our routine system operations cost update to the industry at the regular Operational Forum meetings. These meetings include discussions around the operational actions we have taken in the period between meetings. They give updates on the position of the models, how actual system operation costs are comparing to the modelled targets and explanations of any variations. These meetings have continuously evolved following stakeholder feedback on content and their desire to get an indication of the potential magnitude of incentivised costs broken down by component.

''Should National Grid do more in the Ops Forum?... for BSUoS they now do a forecast at each time... it hasn't been very accurate but that's reasonable.''
Supplier comment, November 2011 RIIO-T1 charging workshop

723 To further increase visibility and breakdown of costs, we publish a number of statements and market reports pertaining to the procurement and use of Balancing Services on the industry information web site. We have particularly undertaken to publish the Monthly Balancing Services Summary[71] (MBSS) Report which sets out volume and cost information associated with balancing service actions taken during the given month. The report is based on the latest data and information available at the time of publication and aims to increase the timelines and visibility of our actions.

724 We will continue to provide BSUoS charge forecasts as part of our routine system operations cost update at the Operational Forum meetings and publish the MBSS to provide further information regarding the impact on BSUoS during the incentive period. The report and the meeting will continue to evolve in order to meet stakeholder feedback and make it align with their needs.

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69 The BSIS element contributed £15m of the £785m total BSUoS revenue in 2010/11
70 http://www.nationalgrid.com/NR/rdonlyres/8FFA9408-9DC7-44C2-AF68-93E684A176D8/47549/CUSC_Section_14combinedmasterclean5July11_FINAL.pdf
71 National Grid: Balancing

''While the MBSS is useful, it would be helpful to have more information on how that is compiled.''
Supplier comment, November 2011 RIIO-T1 charging workshop

725 Some of the uncertainty in BSIS is due to the provision for scheme adjustments via Incentivised Balancing Costs (IBC). These are caused by situations that could either be unforecastable or uncontrollable by the NETSO. Consequently BSIS, and hence BSUoS charges, would be reconciled to reflect the change in IBC.

726 Such within-scheme adjustments would be managed via the provisions for 'Income Adjusting Events' (IAEs) which allow for National Grid, Ofgem or other BSC parties to propose adjustments to the Incentivised Balancing Costs to cater for unforeseen events which have increased or decreased IBC by greater than £2m.

727 Under normal circumstances it should not be necessary to make any adjustments to the models or data used to determine the cost targets against which National Grid will be incentivised. However, we have identified the following specific circumstances where it may be appropriate to make within-scheme changes to the models and/or data that comprise the incentive scheme:

(a) The proposed annual review of models to account for, for example ex ante input inaccuracies, modelling software update and model regression updates;

(b) Uncertainty mechanisms for example brought about by shifts in regulation or step-changes in policy such as EMR and European driven changes. Such changes have the potential to materially impact our performance under the Incentive scheme and, to the extent that it is not possible to forecast their occurrence when scheme parameters are agreed. We consider it appropriate to have the ability to mitigate their effect;

(c) We propose to retain the IAE mechanism as set out above to account for any other unforeseen event; and

(d) Other industry driven changes as those discussed below.

728 Our ex ante/ ex post approach to modelling costs is intended to reduce the uncertainty of the BSIS, and hence BSUoS charges, that may arise from IAEs; i.e. the models have been designed to account for a range of uncertainties not possible with a pure ex ante forecast. The electricity industry will undergo significant change as work streams such as EMR and European Network Codes are implemented. These will drive changes to the balancing services on offer and the actions that we take. To manage this risk and to mitigate against its impact on charges, we have proposed a set of uncertainty mechanisms that seek to limit consumer exposure. We have also set out in our 'Annual Model Review' section, a set of model review points where we will assess the suitability of the models and their inputs to accurately calculate a cost target.

729 We propose that under the incentive scheme, the models are run, calculating the scheme cost target and performance annually. This will therefore provide an outturn performance on an annual basis. For the purpose of calculating charges, the BSIS element will feature and thus be factored into reconciliations on a yearly basis.

730 An annual inclusion of outturn BSIS performance in BSUoS charge calculation will enable the following benefits for customers to be realised:

(a) Costs would be targeted at market participants who where active in the operating environment in the relevant year;

(b) Simpler, yearly reconciliation of costs;

(c) Smoothing of costs and incentive payments as charges will include actual BSIS costs; and

(d) Reduced volatility of charges as BSIS performance is forecast and reconciled for a shorter (1 year) time period.

Industry driven changes

731 As the BSUoS charging methodology is now contained in section 14 of the CUSC, it is subject to open governance arrangements and hence any CUSC party is able to propose changes. There are currently three modification proposals underway that seek to alter the BSUoS charging methodology within the incentive period, and it is likely that more will follow.

732 CMP201 (Removal of BSUoS Charges from Generators) seeks to align GB market arrangements with those prevalent within other EU member states by removing BSUoS charges from generation users. This would further facilitate equitable competition with generation in other EU markets which are not subject to such charges. If approved, the level of charges faced by suppliers could effectively double, placing more importance on accurately forecasting this charge so suppliers can assess their liabilities and manage their own charges to customers.

733 CMP202 (Revised treatment of BSUoS charges for lead parties of Interconnector BM Units) seeks to remove BSUoS charges for Interconnector BM Units which would help remove potential barriers to cross border trade. It will also have the effect of further aligning GB arrangements with those prevalent in other EU member states and is consistent with EU objectives of facilitating cross border access and developing a Europe-wide single market in electricity. As Interconnector BM units form only a small set of the BSUoS charge paying community, this proposal will have only minor impact on BSUoS charge payers in general.

734 CMP208 (Requirement for National Grid Electricity Transmission to provide and update forecasts of BSUoS) seeks to require National Grid Electricity Transmission to provide and update current year and year-ahead forecasts of BSUoS charges. The modification proposal proposes that the forecasts be updated on a monthly basis with commentary and published on our external website. It is important that a holistic decision is made as to whether

information provision can be more efficiently presented to industry via a codified requirement or an incentive mechanism.

735 As part of National Grid Electricity Transmission's stakeholder engagement for the RIIO-T1 price control we discussed transmission charges, and specifically asked for comments on charging volatility. Stakeholders expressed a value for predictability and stability of transmission charges, including BSUoS, and therefore we will continue to review the BSUoS charging methodology to develop ways to improve in these areas.

Summary

736 The BSIS incentive payment forms a small proportion of BSUoS charges; elements such as industry driven changes will lead to greater levels of uncertainty and volatility. However, we recognise that BSIS is a significant element and our proposals seek to reduce uncertainty in charges by putting in place uncertainty mechanisms and model review points that aim to minimise consumer exposure.

737 By implementing a yearly calculation of the BSIS cost target and performance annually to be included in BSUoS charges will deliver value for customers as it will target costs at the active participants within the relevant year and smooth charges as volatility is reduced.

738 We will continue to provide the industry with updates on BSUoS charges through the MBSS, and Operational Forum to increase transparency and predictability of charges. We will also continue exploring opportunities to provide more forecast information on charge components within our influence in order to increase transparency of charges. This will also include continued engagement with stakeholders as we assist with industry driven changes such as CMP 208 and assess the potential to develop further incentive schemes such as a BSUoS forecasting or information provision incentive during the RIIO-T1 period.

SO Innovation

Overview

739 This section sets out how we plan to overcome the challenges we face in operating the system in a changing environment through innovation. We set how we adapt our processes, procedures and commercial arrangements to help us to meet these challenges in a collaborative manner.

740 We will We welcome an innovation fund as stated in our RIIO-T1 TO plan of the maximum 1% of revenue under the Network Innovation Allowance (NIA) to fund innovation activities.

The changing system operator role

741 As outlined above in the 'System Operator Role: Now and into the Future' section, the external environment within which we carry out our role as NETSO will change substantially over the RIIO-T1 period with. To overcome these challenges and to deliver value for end consumers we will need to continue to innovate, technically, commercially and operationally.

742 Balancing the network, minute-by-minute, with less predictable generation sources, coupled with the growing influence of interconnectors and EU energy policy will produce:

(a) An increase in balancing activities due to variable output from wind generation and interconnector trading patterns caused by weather changes;

(b) An increase in system complexity as we operate more sophisticated TO assets that are being installed on the network to maximise the utilisation of existing capacity and new sources of generation; and

(c) A rise in the level of operating reserve needed to maintain system frequency due to the lower predictability of wind.

743 We are already beginning to experience these challenges, with the volume and severity set to increase as we head into the RIIO-T1 period. Innovation in processes, procedures and commercial arrangements will play a crucial role in helping us to meet these challenges, whilst minimising balancing costs and maintaining system reliability. This approach is in line with stakeholder views that we will need to adapt to the energy environment.

We need smarter thinking as well as smarter pieces of kit.'
Stakeholder Comment, RIIO-T1 stage 3 workshop, 15 November 2011

744 In anticipation of the significant increase in wind generation, the connection of larger generation sets, we expect that we, in our role as NETSO, will have to increase the amount of ancillary services procured. Traditionally most of the requirements have been met by thermal generating balancing mechanism units and large industrial demand sites. With the adoption of enabling technologies such as smart metering and smarter grids, the breadth and depth of potential providers of ancillary services should increase significantly. As

such, innovative tools, services, working practices and solutions to contracting strategy and service utilisation will be required.

745 Industry collaboration will be vital to overcome these challenges. We will continue to collaborate with all TOs and DNOs and continue to engage with partners from both industry and academia in the UK and Europe. This should ensure that the best opportunities are taken forward in solving the challenges faced in system operation within the incentive period and beyond. This holistic and broad approach to innovation is supported by some of our stakeholders:

“” *A concern was raised that National Grid can sometimes view innovation from a narrow perspective. It was suggested that it should be viewed on a global level.’*
Stage one workshop report, 14 December 2010

746 Innovation is a fundamental principle of the RIIO framework and will be an essential tool in meeting the challenge to facilitate decarbonisation of the energy industry, continuously improve our processes and procedures; ultimately driving down the cost of system operation to the industry and consumers.

747 This was recognised by our stakeholders as crucial in meeting the challenges of the future and it will be vital that sufficient, timely funding is made available.

“” *Innovation would die off without specific funding.’*
Stakeholder Comment, RIIO-T1 stage 2 workshop, 5 April 2011

What we have done to date

748 We have continually engaged with industry and specialist firms to develop contracting strategies and innovative services to be able to align with the changing network needs. As part of this collaborative approach, we have worked with the leading automotive research company, Ricardo, to explore the potential for electric vehicles to provide ancillary services. We have also worked with a variety of different organisations to understand how they have maximised their potential for innovation.

Case Study: Ancillary services from electric vehicles
As the volume of ancillary services required for balancing the system increases, we are constantly looking to encourage innovative sources of balancing services. To help facilitate this, we undertook a joint research project with the leading automotive research company, Ricardo, to investigate whether a future fleet of plug-in vehicles (PIVs) could help to support our balancing requirements.

This research highlighted the extent to which these balancing services, such as reserve provision, are likely to make it financially attractive for PIV owners to provide them and whether this is a viable source of supplementary future balancing services. In conclusion it was estimated that 6% of our balancing requirements in 2020 could be met by plug in electric vehicles.

749 In order to increase participation in the market for dynamic frequency response, we have developed an innovative contract form in close collaboration with RLtec; that allows the commercialisation of dynamic frequency response from the demand side. In addition, we have looked to

further innovate our frequency control by demand management (FCDM)[72] and STOR[73] service from the aggregation of multiple small demand loads.

750 The Low Carbon Network Fund (LCFN) projects are led by the DNOs and are used to develop technologies, and operating and commercial arrangements needed to provide security of supply as value for money during the move to a low carbon economy. As part of LCFN, we are providing support to a number of projects currently underway and are involved in 3 of the 7 proposals put forward for screening in 2012. We are closely engaging with Northern Power Grid to identify the composition and flexibility of demand to assess how it may be further utilised to provide ancillary services by regulating the voltage of the High Voltage distribution network. We are also working with other DNOs on the wind-twinning work-stream and the development of distribution level ancillary services that could be utilised on the NETS.

751 We have worked with the DNOs to investigate how our operational control systems can be more closely linked to enable more efficient sharing of network data. We have also extended our work on system efficiency with the Transmission Owners and generators, particularly with connecting new users to the NETS or, at times, distribution systems. Innovative commercial agreements will allow systems such as intertrips and/or energy management systems to be fully utilised; and hence to operate the system closer to its full capability.

752 To accommodate and fully utilise the increasing volumes of wind connecting onto the NETS we have been developing trading and contracting options that will enable us to economically manage surpluses of wind energy. We will continue to explore the capabilities of wind farms to provide balancing services, developing new contract forms and control systems to reflect those capabilities.

What we will be doing in the future

753 Going into the RIIO-T1 period, continued collaboration with external companies, academia, Transmission Owners and industry will be key as it will allow a holistic approach to innovation. This will lead to maximum value as we learn from best practice and harness specialist skills. We will be working alongside our TO business to gain the benefits and adapt the lessons and fundamentals of the three pillar innovation strategy[74] as set out in our RIIO-T1 TO plan.

754 The strategy relies on three pillars to deliver successful innovation solutions into our business:

(a) **Identification and prioritisation of research areas**: We will continue to listen to our stakeholders and focus our efforts on delivering

[72] Frequency Control by Demand Management provides frequency response through interruption of demand customers when the system frequency transgresses the low frequency relay setting on site.

[73] Short-Term Operating Reserve is a contracted Balancing Service, whereby the service provider delivers a contracted level of power when instructed by National Grid, within pre-agreed parameters

[74] The 3 pillar approach is set out in the RIIO-T1 innovation Strategy document: Innovation | Transmission: Electricity | National Grid

innovative solutions to address their needs. We will utilise the strength of our own staff to generate ideas. We will continue to scan the technology landscape and work with key suppliers to identify opportunities;

(b) **Harnessing innovative capabilities**: We will continue to build a more innovative culture within our company to make sure that we can deliver our company vision of being an innovative leader in energy management. We will give our staff the tools and time to investigate different innovative solutions and foster an environment where this is the norm rather than the exception; and

(c) **Collaboration with external parties**: We recognise that we cannot fully optimise the use of innovation funding using our own resources. We will continue to build strong links with research institutes, academia, suppliers, manufactures, Transmission Owners, DNOs and other institutions within the energy value chain to harness their capabilities.

755 With an anticipated change in the number and type of providers of ancillary services, it is not fully known how these will be operated. Work will be required to better understand the effects on the network and methods of incorporating such services. Energy storage for example is likely to be a major contender for innovation funding as we believe storage technology could play a significant role in the operation of the transmission networks through ensuring optimal utilisation of renewable generation, and provision of flexible balancing services.

756 We will look to maximise the use of existing customer-facing systems such as Frequency Control by Demand Management (FCDM) and Standing Reserve Dispatch[75] (SRD) so that they can still be used as the communication platforms for any new commercial services. In addition, we are expecting to develop more services through technological and commercial innovation, and increasing uptake in areas such as industry and home smart devices, services accompanying electric vehicles and more widespread use of heat pump technologies

757 It will be vital in our role as NETSO to innovate and evolve our systems, strategies and capabilities at a similar pace to the TOs and DNOs in order to maximise the benefits of the equipment on the system. To that end, the Strategic Asset Management (SAM) strategy and Humber Smart Zone projects are being developed in order to enhance the capability of our TO business to manage its assets and will deliver better quality and improved operational data. Interactions between the SO and TO will be vital in order to make sure that the operational capability of the assets that are determined by the TO are fully utilised.

758 We will therefore need to continue to work closely with all the TOs and DNOs to ensure we modify and adapt our processes and systems to make best use of innovation from all quarters for the GB system as a whole. This

[75] Standing Reserve Dispatch is the despatch system for non BM short term operating reserve providers

collaborative approach will result in greater access to asset performance information; allowing more efficient procurement of balancing services and ensuring continued security of supply. As the LCNF programme matures, and the Network Innovation Competition for TOs begins, it is foreseeable that the need for NETSO involvement will increase over the RIIO-T1 period; requiring considerable investment of time and resource.

759 We will continue to collaborate with the network companies and assist in collaborative projects where benefits may not directly be attributed to our operations but will ultimately filter to cost savings for consumers and increased knowledge and understanding of systems.

760 We will continue looking at creating innovative technical and commercial arrangements to best accommodate wind energy output onto the system. This work will take on a number of forms such as:

(a) Looking at pump scheduling contracts to better align demand at pump storage sites to times of high wind output;

(b) Further development of trading options with wind farms. This is requiring trading agreements to be developed that operate around forecast wind output days ahead of real-time, rather than the traditional 'registered capacity' led approach;

(c) The development of high frequency response contracts from wind farms that enable them to provide this service in isolation rather than having to bundle this with the provision of low frequency response as well; and

(d) The further development and use of SMART techniques (i.e. those which depend on real-time information on network asset state to determine system control actions that best meet user needs.

What does innovation deliver?

761 As we innovate to adapt to technological changes, we will enable provision of services that are more flexible and economic. This will widen the range of services available for balancing the system, thereby introducing greater competition, which will be translated to lower BSUoS charges leading to lower prices for customers.

762 Further development and understanding of control and management systems will enable us to maintain high levels of safety and reliability in our operation of the NETS with increased volatility in energy flows and usage.

763 By facilitating the connection of lower carbon sources of energy and increasingly utilising wind and demand management to balance the system, we will increase our balancing services options, whilst assisting in meeting the renewable energy targets.

764 The benefits of innovation will also extend to existing, ageing assets as asset management strategies are developed, there will be scope for network risk and costs to be minimised. Maximising the value and capacity of existing assets will lead to reductions in system constraint costs. Customers and

stakeholders expect us in our role as NETSO to innovate in line with changes in technology and their needs. Our ability to collaborate with industry participants, specialists, academia and the Distribution and Transmission Owners will allow us to fully understand customers' needs and deliver benefits that add value.

765 Our innovation strategy will drive us to take part in projects led by other industry parties, these includes projects such as those under the Low Carbon Network Fund. These projects will yield benefits to consumers as well as other industry parties as a holistic approach is adopted. An appropriate level of funding allows efficiency and maximum value of these schemes to be realised, greater knowledge and understanding of the network to be gained and the benefits to be passed on the end consumer.

Summary

766 Innovation in all its forms will be a key element to driving our business forward, enhancing our ability to maximise the required outputs for the benefit of consumers and stakeholders alike. The continued development of an innovation culture within our business will create efficient, effective and strategic solutions which are integral to solving the challenges that face the wider energy industry and consumers alike. We welcome an innovation fund as stated in our RIIO-T1 TO plan of the maximum 1% of revenue under the Network Innovation Allowance (NIA). This will enable us to carry out the innovation activities set out above and overcome the future challenges faced by the NETSO and energy industry. The NIA funding profile would be based on the current projected revenues for the RIIO-T1 period as set out below. This would represent an increase in our innovation funding to date and would allow us to not only lead innovative projects but to also collaborate with industry partners to yield maximum industry value.

13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	Total
£16m	£16.8m	£17.8m	£18.8m	£18.9	£19.8m	£20.3m	£20.4m	£148.8m

767 Inevitably with innovation, some benefits will be realised years into the future, this will allow us to achieve continuous efficiency improvements past the incentive period to which the innovation fund relates.

768 Without innovation, transitioning to a low carbon economy and achievement of the UK Government's carbon reduction targets becomes much more difficult and potentially more costly. The sooner that innovative solutions to the challenges can be realised, the greater the benefit to industry, the environment and the end consumer.

769 Innovation is supported by our stakeholders with many seeing it as absolutely critical in enabling us, and the wider energy sector, to operate a sustainable, reliable network affordably.

Stakeholder Engagement

Overview

770 As part of the SO Incentive development process, we have engaged with our stakeholders, sought their views on incentive options for the RIIO-T1 period and used their views to help shape this submission. This section describes the engagement we have undertaken, provides a summary of stakeholders' views on the incentives and how they have been incorporated into our plan. It then outlines the next steps we will be taking with our stakeholders.

The Engagement Process

771 We have engaged with stakeholders, discussed the proposed incentives, heard and understood their views and have incorporated them into our submission. Our engagement has covered a number of specific activities, including:

(a) An SO Incentives stakeholder workshop held in February 2012;

(b) Attended industry meetings to discuss the proposed SO incentives;

(c) A number of bilateral stakeholder meetings; and

(d) A stakeholder consultation on our initial proposals for Renewable Generation Forecasting and Information Provision.

772 Following publication of Ofgem's SO Incentives from 2013 consultation document on 31 January 2012, we were able to discuss with the industry some of Ofgem's initial views on both existing and new possible incentives to be implemented from 1 April 2013.

773 We held a stakeholder engagement workshop following the February 2012 Operational Forum meeting; this was attended by participants representing a range of industry bodies. The workshop was used to gauge industry views on specific topics such as scheme length, Black Start, Transmission Losses and Renewable Generation Forecasting. We published a report summarising the industry views expressed at the workshop[76].

774 Following feedback from the February workshop, we published a consultation to seek industry views on our initial thoughts and proposals for the new incentives on Renewable Generation Forecasting and Information Provision. The consultation provided background to the proposed forecasting accuracy incentive; sought views on our initial thoughts and the value to the industry from these incentives. We attended the Commercial Balancing Services Group (SBSG) meeting to further discuss the consultation and subsequently received three responses which we published on our website along with the consultation document[77].

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[76] http://www.nationalgrid.com/NR/rdonlyres/20DE4188-C623-45F3-9DA2-4E6E87987E6C/52393/StakeholderEngagementWorkshop_SummaryReport_March2012Final.pdf
[77] National Grid: System Operator Incentives - Industry Workshop

775 We attended a range of industry meetings and workshops to discuss our views and initial thoughts on scheme parameters and proposals with industry participants. Their thoughts were captured and incorporated into the scheme design and proposed incentive options. We also carried out bilateral meetings with stakeholders on specific topics, some of which have been incorporated into our plans and while others, such as the mechanism by which we will interact with the Scottish TOs, are still being developed.

776 During our RIIO-T1 TO stakeholder engagement, we discussed and gathered stakeholders' views on a number of key areas relating to NETSO activities both through workshops and written consultations. We have also used the outcomes from this engagement to inform our submission. These areas include:

(a) NETSO and TO interaction;

(b) Security standards;

(c) Pricing volatility and charging; and

(d) Innovation.

777 As part of our RIIO-T1 engagement we produced the Electricity Scenarios Illustrator model (ELSI)78, which has enabled stakeholders to see the impact different generation and network investment decisions will have on the transmission system, including showing the impact on constraints at the main pinch points and the overall network losses. The model has helped to open up the network to stakeholders and demonstrate how interactions between the TO in terms of investment and the NETSO in terms of operating the system can seek to provide the most cost efficient solution. This was well received by the industry and has been seen as a positive step by National Grid to increase transparency.

778 We have also drawn on the stakeholder responses Ofgem received to its 'System Operator (SO) Incentive Schemes from 2013: Principles and Policy79' consultation, which was published in January 2012. We have been mindful of the feedback we have received from stakeholders regarding the number of consultations going on in the industry and the draw on their time. As such, we considered and incorporated the consultation responses published by Ofgem in the development of our plans.

779 We have engaged with our stakeholders throughout the current TCPR4 price control period as the SO incentives have evolved and been developed. The last significant review of the incentives took place in 2010/11; where the Balancing Services Incentives Scheme (BSIS) transitioned from being an annual ex-ante agreed cost target to the current 2 year scheme with modelled cost relationships; this is the current scheme operating for 2011-13. Many of the comments made by stakeholders during the 2010/11 consultation for the current scheme have been reflected in responses to both the Ofgem consultation and the stakeholder workshop we held in February 2012.

[78] http://www.talkingnetworkstx.com/consultation-and-engagement.aspx
[79] http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=277&refer=Markets/WhlMkts/EffSystemOps/SystOpIncent

780 Our engagement process has been open and inclusive with all our consultation material and reports published on our Talking Networks[80] and National Grid[81] websites. We have also attended industry meetings to discuss the proposed SO incentives, as well as holding a specific workshop, in order to reach as wide a number of stakeholders as possible.

781 Following the submission of this plan, we will be presenting our proposals at the June 2012 Operational Forum to inform stakeholders of our proposals.

Stakeholders' views and how they have been incorporated into our plan

782 Stakeholders have provided us with a variety of views on the different elements of the SO incentives. In a number of areas they are in general agreement, such as Transmission Losses, whereas in other areas, such as BSIS, they have more diverse views. A number of stakeholders have said they wish to see more details regarding the incentives before they can be fully supportive of the proposals.

Balancing Services Incentives Scheme (BSIS)

What stakeholders said	What is in our May 2012 plan
Whilst many stakeholders support a longer time frame, a number were concerned about increasing the BSIS incentive beyond the current two years due to future uncertainties and policy changes such as EMR. *Stakeholders favoured regularly reviewing the incentive to ensure it remains relevant.*	*We have designed the incentive framework such that we have review points to assess suitability of the scheme design and parameters to model target costs and increase caps/ collars and sharing factors as confidence in modelling grows.* *We have proposed an annual model review process to ensure that our models and the inputs continue to accurately reflect the operating environment.* *We have also put in place specific uncertainty mechanisms to mitigate the risk of changes in the operating environment during the RIIO-T1 period.*
Many were concerned that the use of uncertainty mechanisms, re-openers or similar income adjustment events will increase the unpredictability of the BSUoS charges at a time when they	*We are already working with stakeholders on providing additional information and increased transparency around the BSUoS charges through the Transmission Charging Methodology Forum.*

[80] http://www.talkingnetworkstx.com/consultation-and-engagement.aspx
[81] http://www.nationalgrid.com/uk/Electricity/soincentives/IndustryWork/

are seeking greater charging stability.	*In our plan we have proposed to continually engage with customers throughout the RIIO-T1 period and provide regular updates through the Operational Forum and the publication of incurred costs through the Monthly Balancing Services Statement (MBSS).*
The BSIS model is complicated and should be simplified.	*We have been redesigning our models to simplify them and make them more accessible for stakeholders. We have outlined the changes we have made to the models in our business plan and kept these as simple as possible whilst ensuring that they are robust enough to cater for change.* *We have also reviewed the methodology that sets out the ex ante or ex post categorisation of model inputs based on our ability to forecast and control them.*

Black start

What stakeholders said	What is in our May 2012 plan
There was general agreement amongst stakeholders that we have little or no influence over black start cost drivers. With many current Black Start power stations closing over the coming years, stakeholders felt we would incur higher costs contracting with new stations. Again stakeholders felt this was outside of our control.	*We have set out the principles and assumptions behind our forecast for Black Start costs and designed an incentive mechanism that maintains the incentive on us to deliver an effective and efficient Black Start service with the future Black Start costs.*
Stakeholder suggested a commercial market for black start consisting of market agreements for the service. Another suggestion was that we have a licence obligation to maintain a certain number of stations who are contracted to provide this service.	*Our incentive proposal maintains the incentive on us to minimise costs and continue to innovate in the way we procure Black Start.*

Transmission losses

What stakeholders said	What is in our May 2012 plan
There was limited support for this incentive amongst stakeholders with many saying the NETSO cannot influences losses on the system. They concluded the NETSO was not perhaps the appropriate industry body to be incentivised in reducing losses.	*We have proposed to unbundle transmission losses from the BSIS to reflect that we have low ability to control transmission losses. This will reduce scope for windfall gains and losses during the incentive period whilst maintaining an incentive on us to take action to reduce losses where possible.*

Information Provision (Renewable Generation Forecasting)

What stakeholders said	What is in our May 2012 plan
Many stakeholders felt we were well placed to provide this information to the industry, although a number said it was of greater interest to generators rather than suppliers. *Stakeholders were seeking to receive more than just a simple national picture and they were particularly interested in the provision of wind cut-out information.*	*We propose to enhance current information provision on renewable generation and look at a number of options for doing so.*
Stakeholders believed there was value in National Grid providing wind power forecasts. They believed the greatest value would be added through providing an accurate forecast in short lead times due to the intermittency of wind. *Stakeholders expressed a desire for more information on how wind forecast data will affect our actions in balancing the system.*	*We have proposed a new financial incentive based on the level of forecast accuracy in order to drive improvements to the forecast over time.* *We will continue to publish a summary of our balancing actions post event through the Monthly Balancing Services Statement (MBSS) and provide regular updates and discussion through the Operational Forum.*

SO/TO interaction

What stakeholders said	What is in our May 2012 plan
Stakeholders support greater SO/TO interactions with the aim of minimising system costs, delivering new connections and improving the management of outages. Transparency of decisions taken between the parties and the benefits to customers will be key.	*We have engaged with the Scottish TOs throughout the development process.* *In addition we have further focussed the constraint cost incentive on the areas that we can control and/ or forecast through enhancements to the constraint model.* *We also include a proposal to better reflect our ability to control costs associated with Scottish constraints such that they are managed by the party best placed to do so.*

Next steps

783 We will be carrying out a series of joint engagement workshops with Ofgem to discuss with stakeholders our incentive proposals. These are expected to run in September during Ofgem's initial proposals consultation process. This will give stakeholders an opportunity to gain an understanding of our proposals and provide their feedback. Further information regarding this process will be published in due course.

Appendix A: Energy Modelling – current design and performance

Overview

A1 This appendix contains an overview of each energy sub-model within the energy model along with model performance to date. We set out the analysis undertaken to review performance of the current scheme energy models which will underpin the further development work as set out in the 'Energy Modelling' section. This review has also been carried out in light of the reassessment of the treatment of modelling inputs such that those elements we cannot reasonably control and/ or forecast are input to the models on an ex post basis.

Background to the energy models

A2 In most instances, regression analysis is used within the models in order to represent the variables and model the relationships between Balancing Services Incentive Scheme (BSIS) cost drivers and the costs themselves.

A3 Regression Analysis is used to determine the type and strength of relationship between two or more variables. This type of analysis has been employed to model BSIS forecast costs as it facilitates an understanding of how a dependent variable changes when independent variables are altered (e.g. the extent to which BM Prices are affected by wholesale power price). The impact of introducing different variables can also be assessed using regression analysis in order to determine which bears the greatest relation to the dependent variable (or BSIS cost) in question.

A4 The result of this process is therefore that each model consists of a number of variables (which produce the best level of fit) and each variable has a coefficient in the regression which ultimately defines the regression equation.

A5 Due to the ex post/ex ante approach to determining BSIS target costs, the relationships between the chosen variables within the models (regressions) form part of the current scheme (ex ante). Thus, each model includes an ex ante defined relationship. These defined relationships are used throughout the duration of the scheme to calculate an ongoing scheme target with use of both ex ante and ex post inputs.

A6 Each model within the Energy Model will therefore (typically[82]) comprise:

(a) An ex ante defined relationship between a number of variables;

(b) A number of ex ante inputs; and

(c) A number of ex post inputs.

A7 This section details what the current model regressions are and the variables to be used within each regression.

[82] Some models will not include both ex ante and ex post inputs (e.g. the Energy Imbalance model does not consist of any ex ante inputs) however all models will include an ex ante relationship

Energy Imbalance

Energy Imbalance Model Overview

A8 Following the review of cost drivers during the SO Review in 2010, two inputs to the Energy Imbalance model, namely Net Imbalance Volume (NIV) and wholesale power price (SPNIRP) were input ex post to the model using outturn data. This eliminated the requirement for the model to estimate, firstly, possible NIV outcomes and, secondly, SPNIRP values for those NIV outcomes.

A9 The current Energy Imbalance cost model firstly predicts a BM pseudo price using NIV and SPNIRP ex post values. This is then multiplied by ex post NIV to give target energy imbalance cost.

A10 BM pseudo price is a key variable in our internal costing methodology. The price is a representation of the volume weighted average price that would be paid to resolve NIV in a particular half hour. The average is based on the cost of actions if only the cheapest submitted options were taken and no other considerations were made.

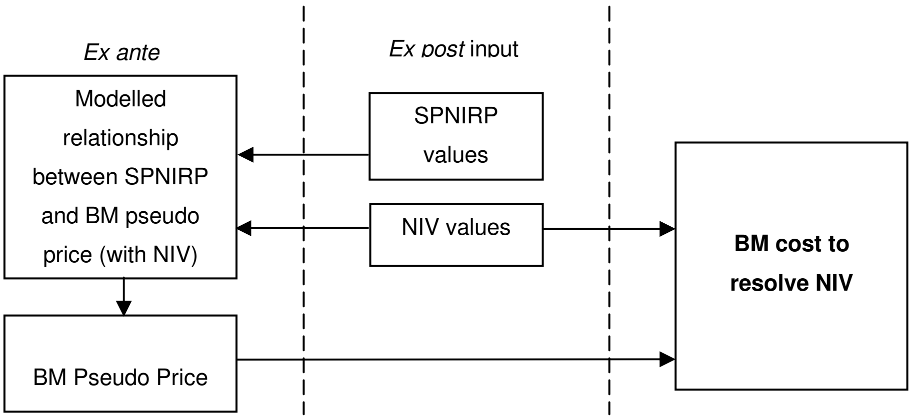
A11 In a long market the submitted Bid prices are used in the calculation for that half-hour. In a short market the submitted Offer prices are used in the calculation for that half-hour

A12 In order to determine the load points of each unit and hence how much volume is accessible the Final Physical Notification, the Maximum Export Limit and Stable Export Limit are used. Then the submitted prices and associated volumes are then used with the accessible volume to create a list of feasible actions.

A13 These actions are then stacked in effective price order and the volume of each action that is need to reach the market length is recorded. A volume weighted average of these prices is then produced for each half hour, creating BM pseudo price.

A14 The current Energy Imbalance model, is demonstrated by the diagram below:

Current Energy Imbalance Cost Model

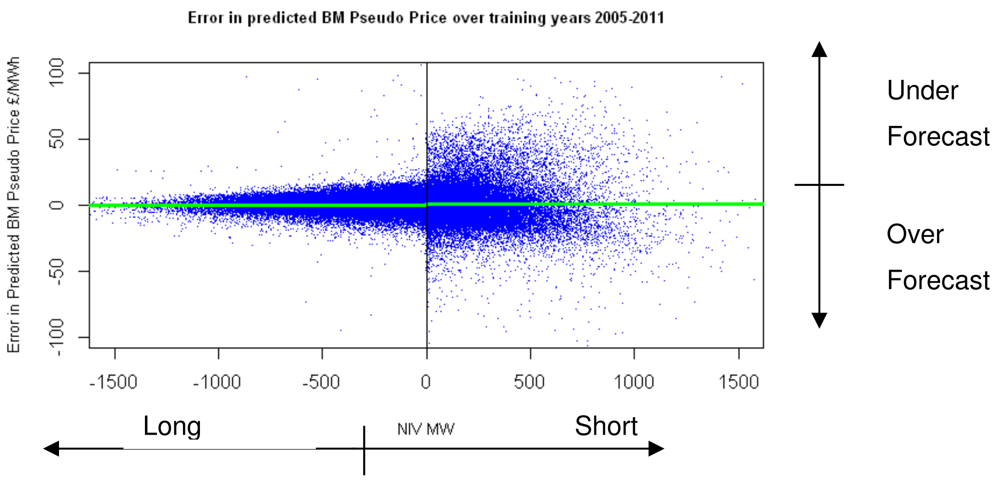


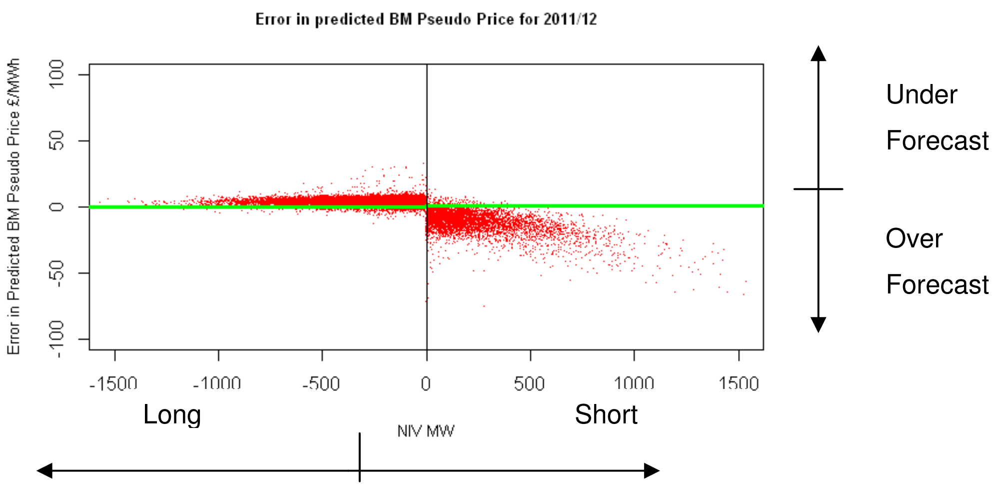
Model Performance

A15 The current model is not accurately modelling the BM pseudo price which when multiplied by ex post NIV results in a target cost significantly higher than outturn costs for the latest year 2011/12. Despite the model providing an overall good level of fit, the current model over forecasts for 2010/11 and 2009/10 and under forecasts for 2005-2009.

A16 The chart below demonstrates the performance of the current model across the years. The green line represents the best fit of the training data[83] which demonstrates that the model works. There is individual variation, but this is balanced such that the average is 0.

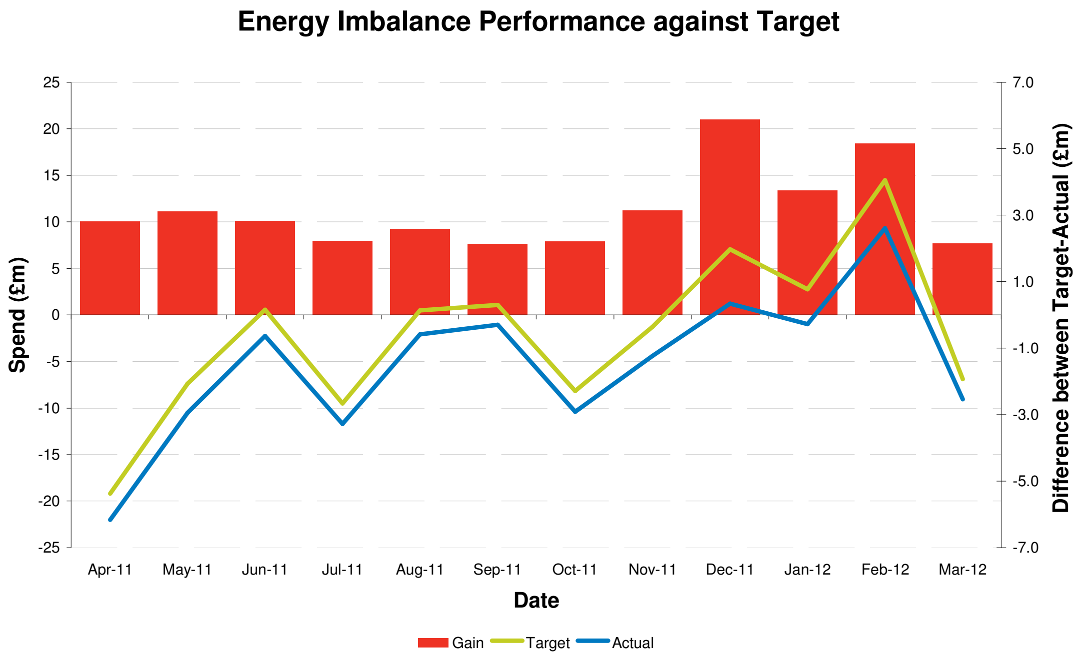
A17 The second plot shows the year 2011/12. It can be seen that when the market is long the model is under forecasting the price and when the market is short the model is overforecasting the price.





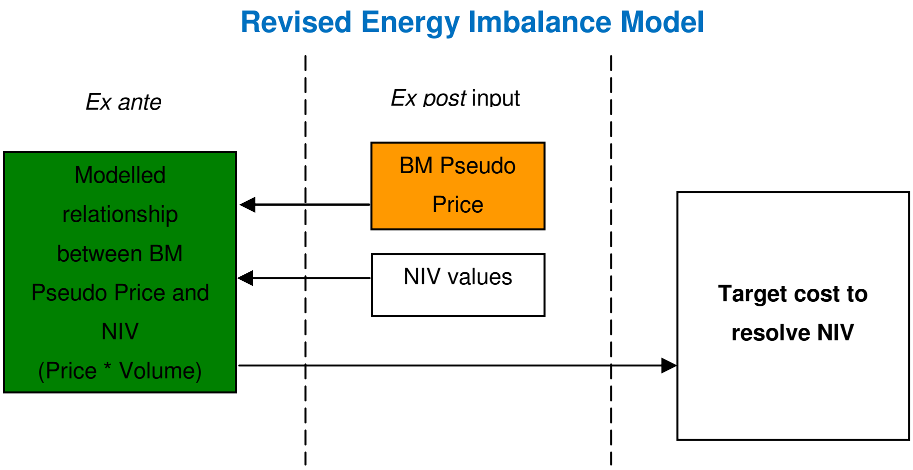
A18 When this forecast price is then multiplied by the settlement period NIV it gives the energy imbalance target cost. Due to the inaccuracy in the price model the outturn costs were lower than the target costs. This varied between £2m and £5m per month. The largest discrepancy occurred between December 2011 and February 2012 as demonstrated in the chart below.

[83] Training data is based on a dataset of ex post variables for 2005-2011.



A19 The BM pseudo price model inaccuracy can be linked to the warmer than average weather over the winter of 2011/12 and the prominence of coal over gas as the main provider of based load power generation, these effects were not seen in the training history.

A20 As set out in our plan, we propose that BM pseudo price is treated as ex post within the models. The revised Energy Imbalance model is therefore demonstrated by the diagram below:



Margin Model: Current Model

A21 Margin costs are incurred when National Grid synchronises additional units onto the system in order to ensure that the Short Term Operating Reserve Requirement (STORR) is met. The calculation of the STORR at any time is based on multiple factors, over which we have varying levels of control. This includes the ability to forecast demand, the reliability/variability of generation, electricity market behaviour and the reserve required to meet response requirements which themselves are influenced by several factors. The STORR is set such that there is a risk of only 1 in 365 days that total demand will not be able to be met. Setting the STORR is a careful balance:

(a) A reduction in the requirement implies less expensive system operation;

(b) Achieving cost reduction through the reduction of this requirement, without detailed understanding through improved modelling, implies an acceptance of higher risk of demand disconnection; and

(c) There are also additional drivers with potential to increase the STORR requirement to maintain a static risk profile. These additional drivers need to be correctly reflected in the models.

A22 The margin model is separated into volume, price and total cost elements. These three elements (the margin volume model, the margin price model and the resultant margin cost model) are detailed in turn in the sections below.

A23 Outturn Margin volume has been modelled on the basis of the following equation/ variables:

Margin Volume = STORR + NIV – Headroom

A24 Headroom created by reduced output from self-despatched generation units, coupled with a longer market, reduces the need of the system operator to create margin by taking actions (and therefore the cost associated with those actions). Such actions, for example, would be to reduce the output on a generating unit from its maximum export level and synchronising a generation unit to maintain energy balance. For this reason, headroom is also known as ‘market provided reserve’.

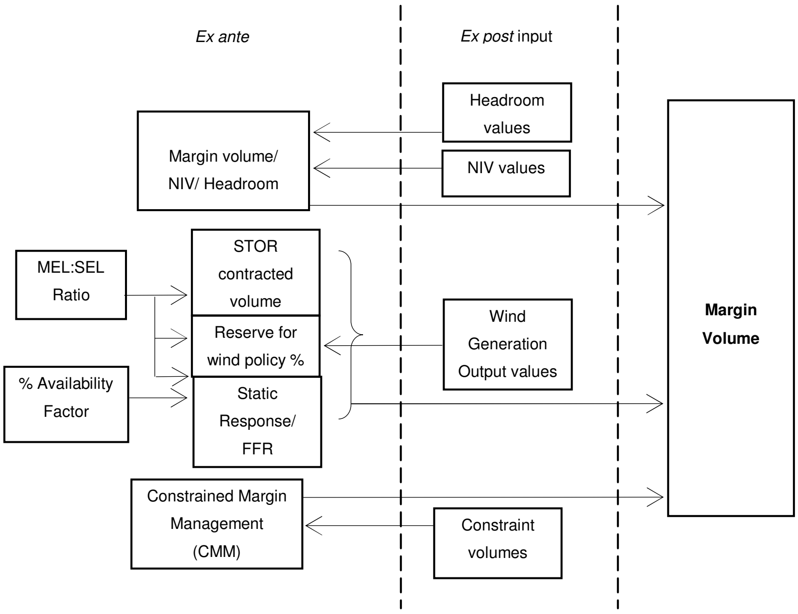
Margin Model: Operating Reserve Model

Current Model and Coefficients

A25 The current volume model attempts to predict the total volume of margin actions taken by us by using a combination of linear regression modelling on historic half hourly data and monthly volume adjustments to account for differences in contracted services across the history and to cover the effect of wind generation variability.

A26 The Current Margin Volume model is demonstrated by the diagram below:

The Margin Volume Model



A27 In the linear model, historic margin actions are modelled against dummy variables for daytime summer, evening summer and daytime winter along with dummy variable for pre-November 2008 or post-November 2008. Ex post variables of NIV and Headroom are also included, this means that the STORR is assumed to be the same except for the difference between the dummy variables. November 2008 represents a change in the STORR setting methodology with a resultant decrease in requirement and a knock-on reduction in the volume of actions taken.

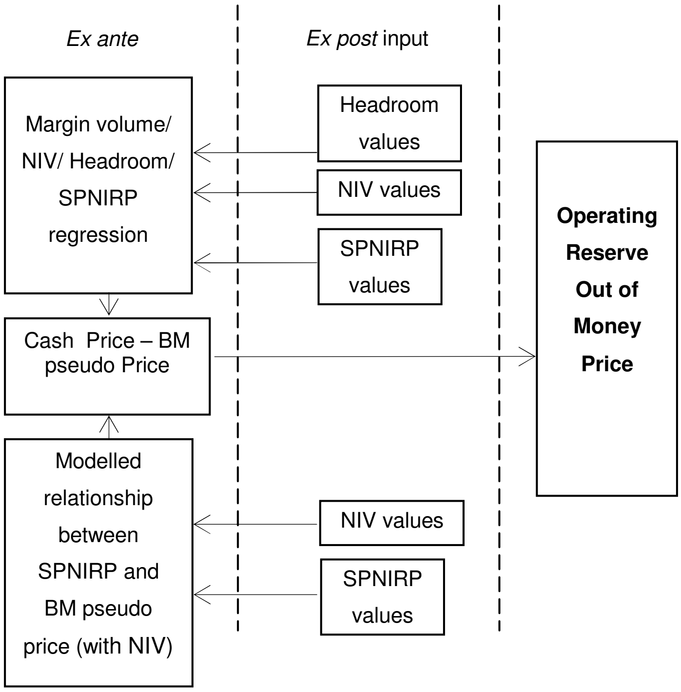
A28 The wind adjustment factor takes ex post wind generation levels which are averaged to a monthly resolution and then applies an ex ante wind reserve policy to derive the volume of margin actions that would have been required for that level of wind. This volume is then compared to the baseline wind requirement for that month in the historic data, and the difference is added to the total margin volume target.

A29 The level of contracted services such as STOR, Static response and Firm Frequency Response will have an offset on the amount of margin actions that were taken. The level of these contracted services vary across the history. To adjust for the variation across history and in the forecast levels compared to history, the difference from a baseline level is calculated. This difference is then converted to a margin volume offset and added to the total margin volume.

A30 The corresponding price model for operating reserve uses the BM pseudo price model and a linear regression model to calculate the operating reserve cash price per settlement period. Subtracting the predicted BM pseudo price from the predicted operating reserve cash price gives the operating reserve out of money price which when multiplied by the predicted operating reserve volume model gives the operating reserve costs.

A31 The Current Margin price model is demonstrated by the diagram below:

Margin Price Model

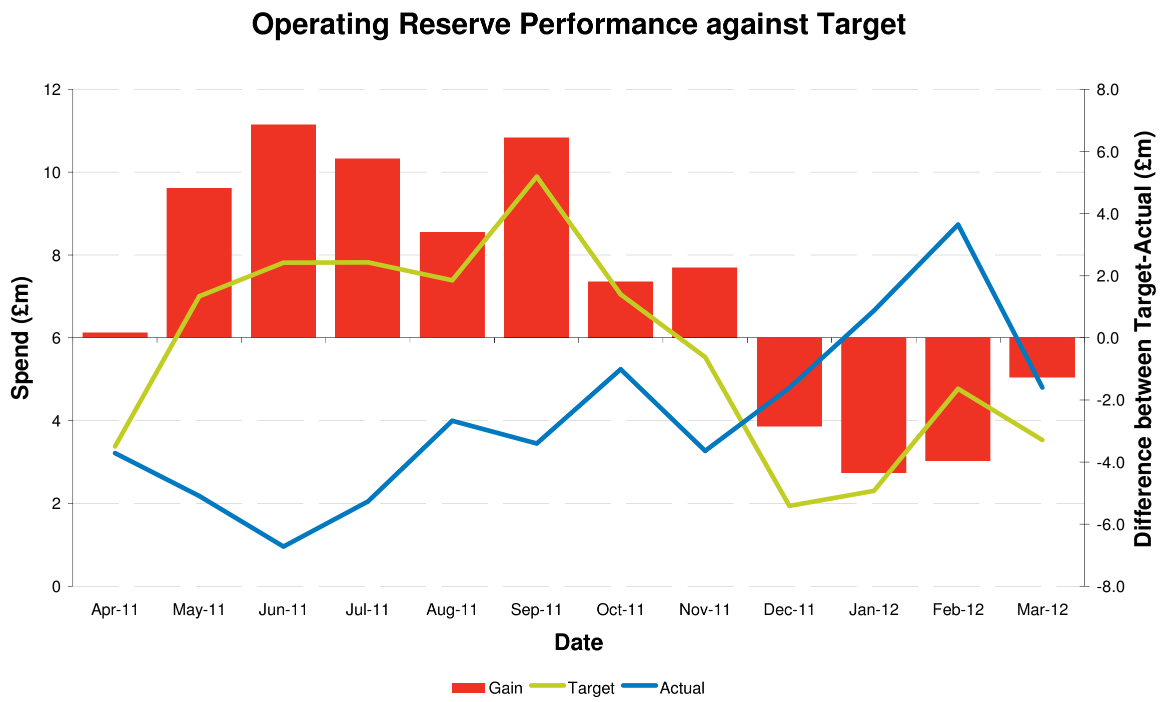


A32 The volume adjustment costs are calculated using the volume weighted monthly average operating reserve out of money price, multiplied by the target volume for each adjuster.

Model Performance

A33 The performance of the volume model is very difficult to asses as any difference in outturn volume when compared to target could either be the result of our actions or error from the target model. This is compounded by the design of the overall model whereby it is the total cost target that is optimised, not each specific component.

A34 The use of dummy variables for daytime summer, daytime winter and evening summer in the volume regression model with no intercept means that any margin volume outside of these times is not included in the model. Some of this volume is covered by the monthly margin volume adjustments although some will be considered an error in the volume model but may have little effect on costs. The outturn vs forecast can be seen in the following chart.



A35 Sustained availability of units to provide reserve at much lower prices than have been historically available led to savings by us during the first two thirds of the 2011/12 financial year. Plant losses at the end of the year coupled with a large drop in temperatures at the end of January led to shorter markets. Exceptionally high prices observed in France put added pressure on markets, resulting in us having to rely on higher priced units than forecast.

Margin Model: BM Start-Up Model

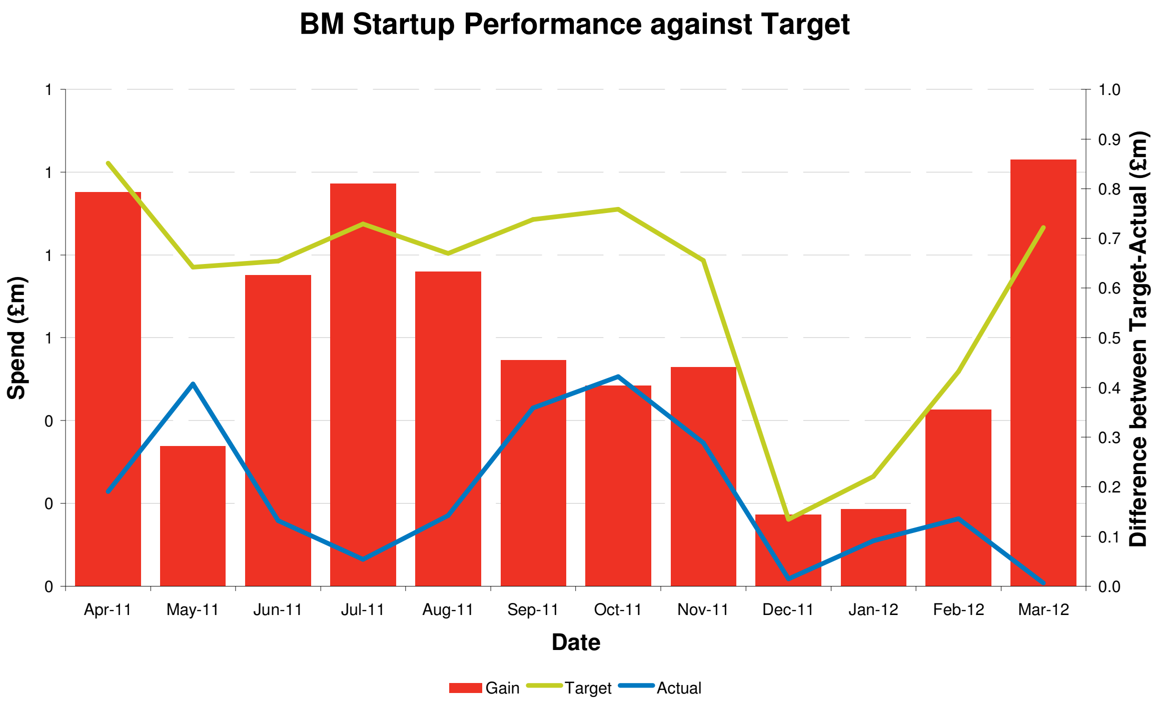
Current Model and Coefficients

A36 The current BM start-up model is a linear regression model which models the costs associated with BM start-up directly. This model uses coefficients of monthly average margin price and an additional coefficient of monthly Average Margin price during British Summer Time. The monthly Average Margin price is itself derived from the margin model.

A37 In previous years BM start up costs were modelled as a function of the number of actions on oil fired generation, however the decline in use of these units led to a change in modelling approach to look at just a historic relationship with margin price.

Model Performance

A38 Favourable system conditions throughout the year allowed us to meet our margin requirement without the need for many BM start-up actions. As a result outturn costs were consistently below target for 2011/12 which varied between £0.2m and £0.9m per month. The prominence of coal over gas ensured that the additional units that we brought on were gas units, which inherently have shorter run up times and subsequently lower startup costs in general. The chart below shows the forecast vs outturn.



A39 Whilst the costs as a percentage of the total cost are low, the lack of causal drivers in the model means that it fails to cope with changes during 2011/12 compared to historic trends. One of these changes is that gas was the marginal plant type for a large part of 2011/12, and BM start-up costs are typically incurred for warming coal and oil plant. Regressions that include the most recent data are necessary to improve the model.

Margin Model: Short Term Operating Reserve (STOR) Cost Model

Current Model and Coefficients

A40 The current STOR cost target model sums the costs of both STOR availability and utilisation payments. The STOR availability target costs are based on an ex ante forecast of the volume of STOR that will be contracted, multiplied by an availability factor and an ex ante forecast average availability price. The STOR utilisation target costs are based on an ex ante forecast of the total margin volume target, multiplied by an ex ante forecast utilisation price.

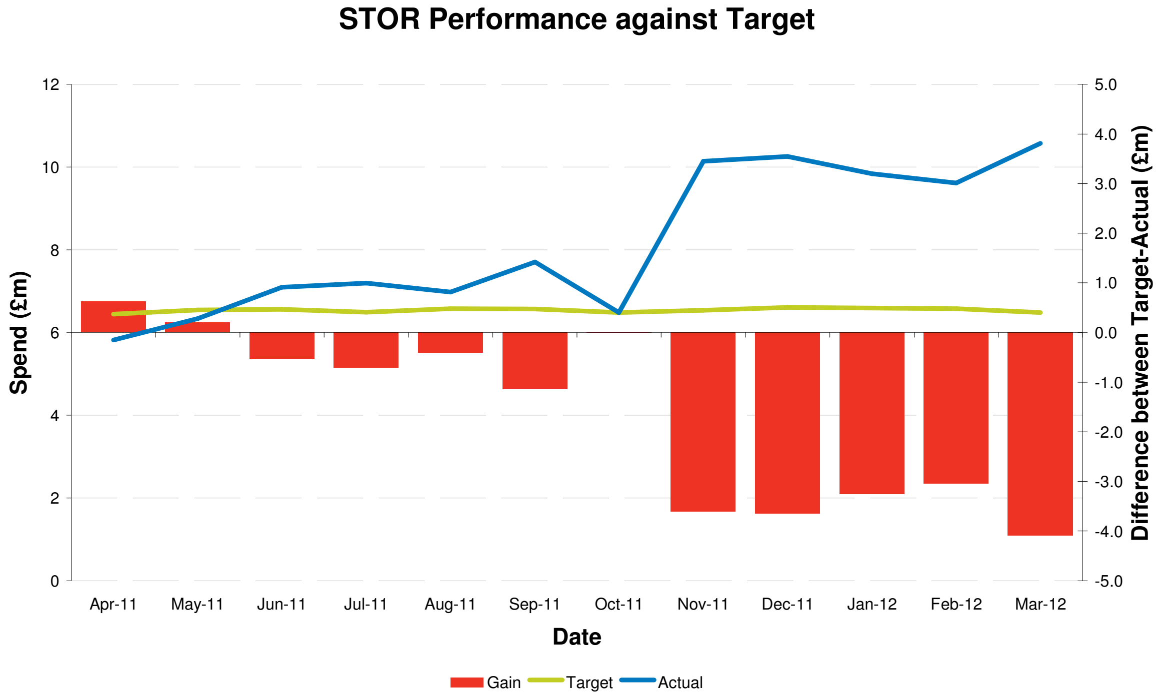
Model Performance

A41 The performance of this model once again is difficult to assess as it is incorporated into the overall performance across the margin model and the energy imbalance model. The target availability price forecast was above the outturn availability price. However the exact reason for this cannot be determined. From April until August 2011, the outturn availability volume was lower than the target; however from November 2011 to March 2012 the outturn availability volume was significantly higher than the target. This outturn level is a result of a combination of the volume and prices tendered by the market and the choices taken by us to deliver the most economic solution.

A42 The availability and utilisation prices for STOR have out-turned lower than the target for 2011-12. This is in part due to the assessment decisions we make at each tender round and the work we have undertaken over several years to develop the STOR market.

A43 The target for utilisation volume is currently set at 1% of the target margin volume for the year. The performance of this target is obviously influenced by the margin volume forecast performance, however outturn data shows levels of utilisation in the 10% region rather than 1%.

A44 In total there are several deviations from target that result in total STOR costs being varied but quite balanced between April and October. Since November 2011 the outturn costs were higher than the target costs. This can be seen from the following chart.



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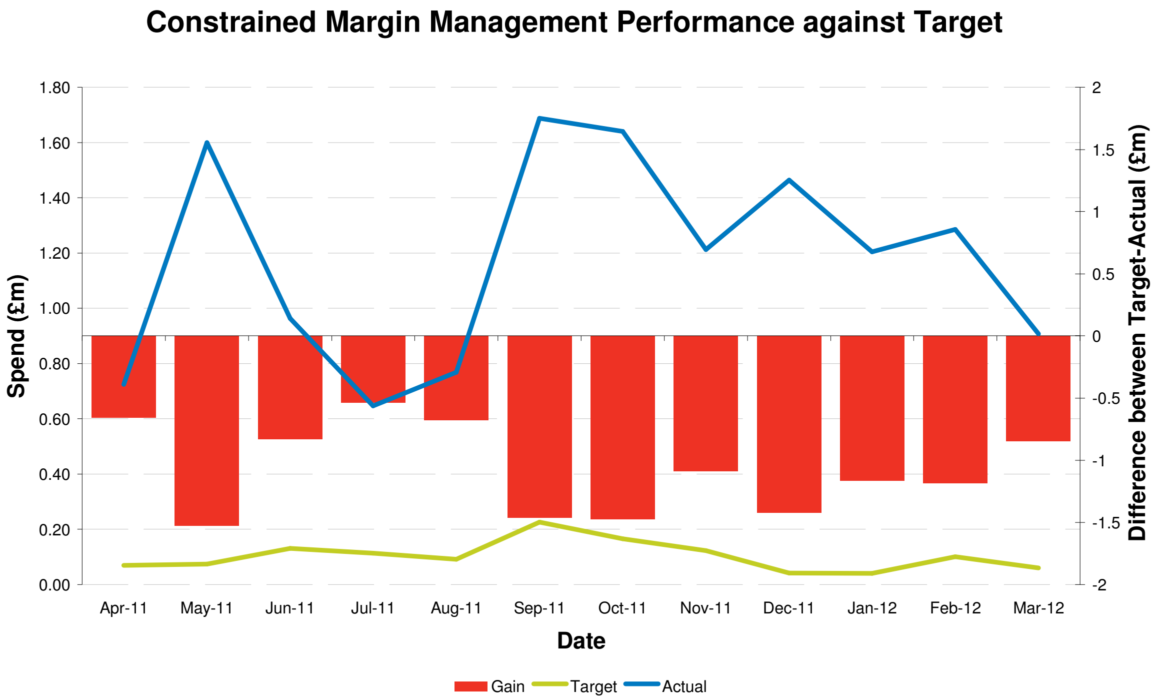
Margin Model: Constrained Margin Management

Current Model and Coefficients

A45 The current CMM cost forecast model uses the average monthly operating reserve price multiplied by a margin cost ratio factor multiplied by a forecast of CMM volume. The CMM volume regression model uses a forecast value of Cheviot boundary constraint volumes from the Constraint model to predict CMM volume.

Model Performance



A46 The performance of this model is driven by the performance of the Constraint model in forecasting volumes across the Cheviot boundary. The outturn costs are consistently higher than the target during 2011/12, reflecting the shortcomings in the current constrain model to identify constraint volumes. The areas that we have identified in the 'Constraints Modelling' section in this plan should improve this area of the current CMM model.

Frequency Response

Current Model and Coefficients

A47 The current model splits Response into Balancing Mechanism (BM) costs and Ancillary Service (AS) costs. BM costs being Bid and Offer costs which are calculated by multiplying their respective Volume and Price totals (these are both regression models).

(a) BM Bid volume regression on coefficients: NIV, Trend, Average Headroom volume and Average Winter Headroom volume;

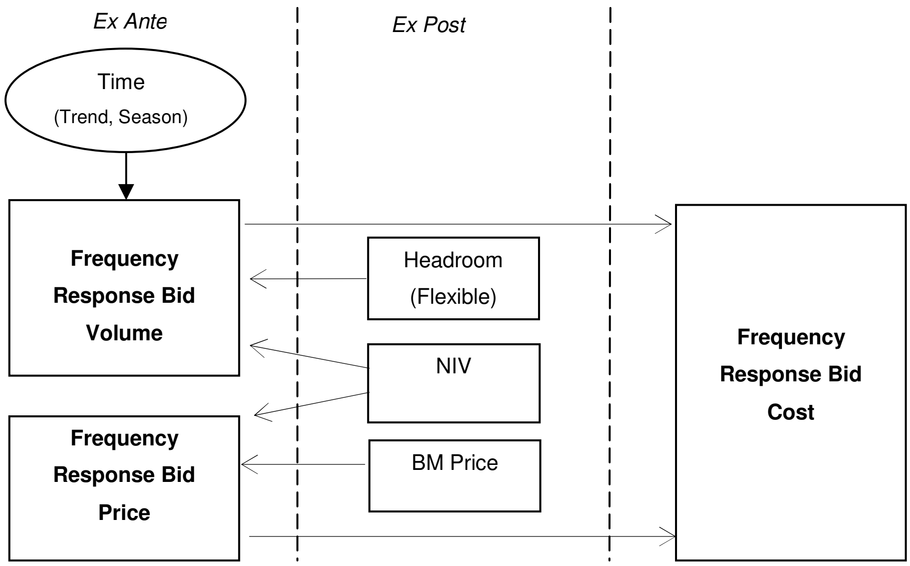
(b) BM Bid price regression on coefficients: Average BM price;

(c) BM Offer volume regression on coefficients: Summer, Average Nuclear volume, Log of Demand, NIV, Average Summer Nuclear volume, Log of Summer Demand and Average Wind volume;

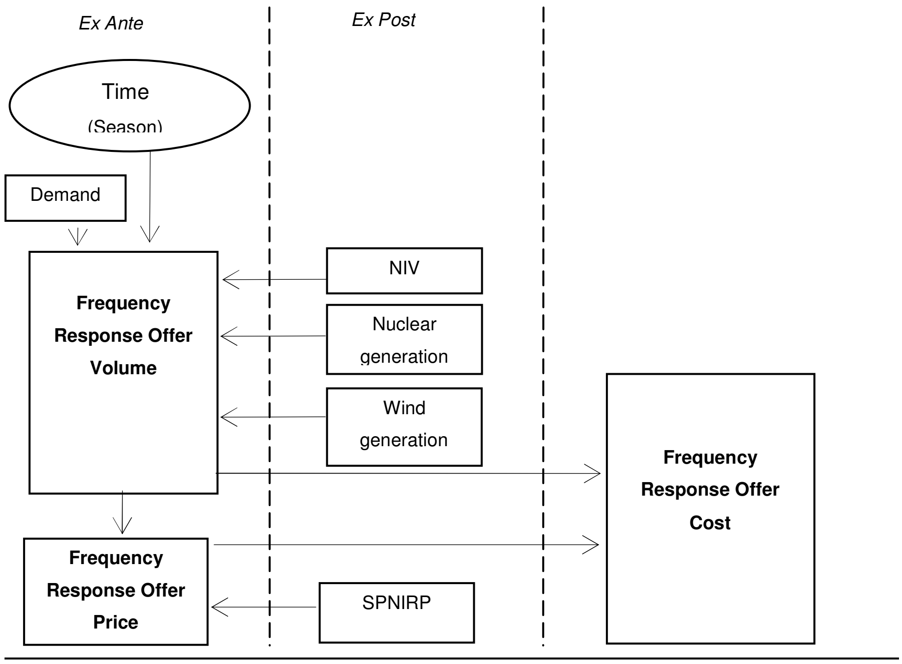
(d) BM Offer price regression on coefficients: Average SPNIRP volume and BM Offer volume (above); and

(e) AS costs are regression on coefficients: Average Summer SPNIRP volume and Average Summer Nuclear volume.

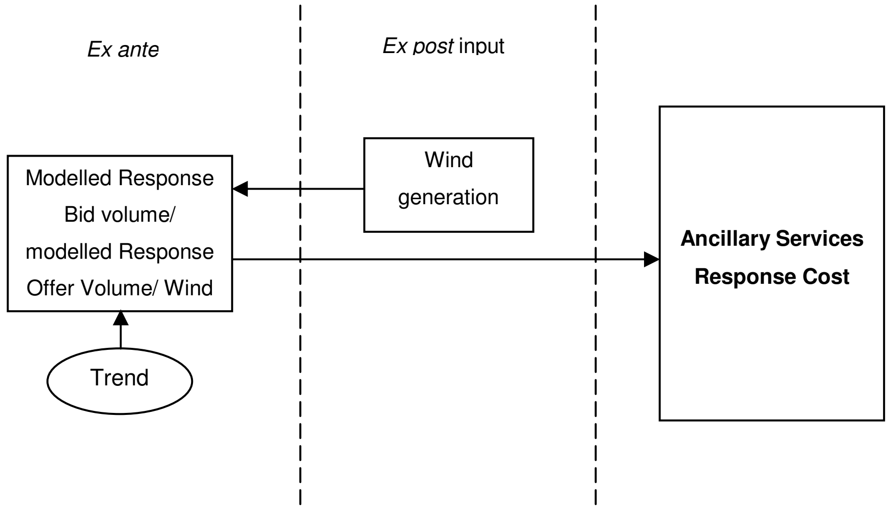
Frequency Response Bid Cost Model



Frequency Response Offer Cost Model

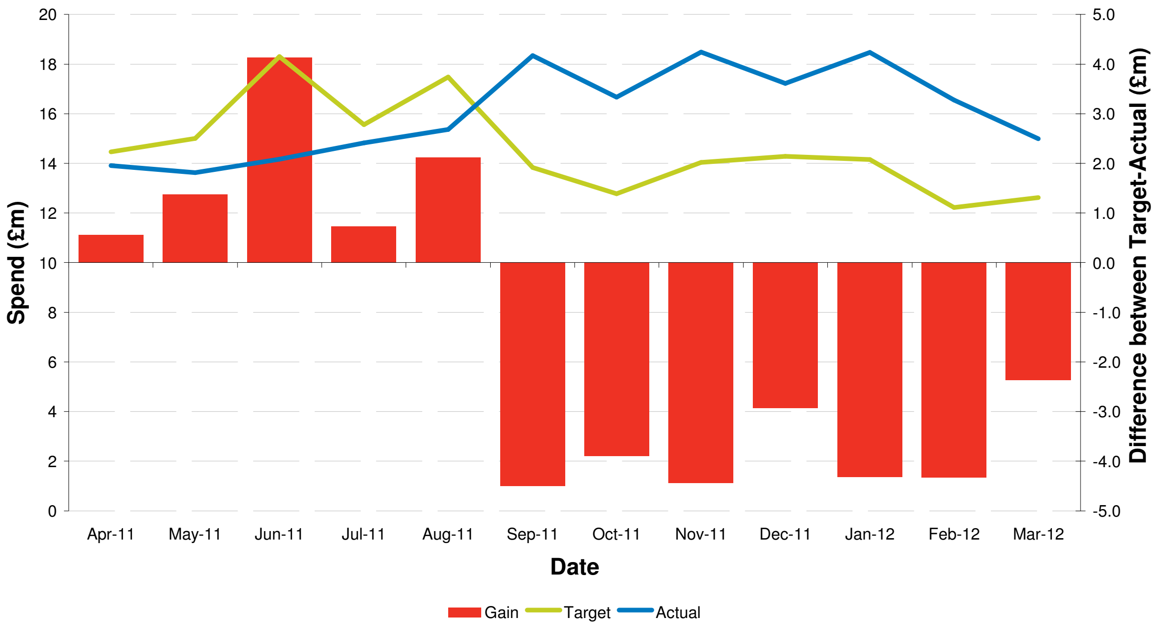


The Ancillary Services Frequency Response cost model



Model Performance

A48 Increased response holding in the Balancing Mechanism was required from September 2011 onwards due to unforeseen delays in returning transmission outages. During the autumn this was compounded with delays in the return of a bi-pole on the French interconnector leading to additional response being held overnight. The performance of the model is shown in the graph below.



Fast Reserve

Current Model and Coefficients

A49 The current model sums: BM costs and AS costs. BM being Bid and Offer costs which are calculated by multiplying their respective Volume and Price totals (these are both regression models).

(a) BM Bid volume was a fixed number based on history;

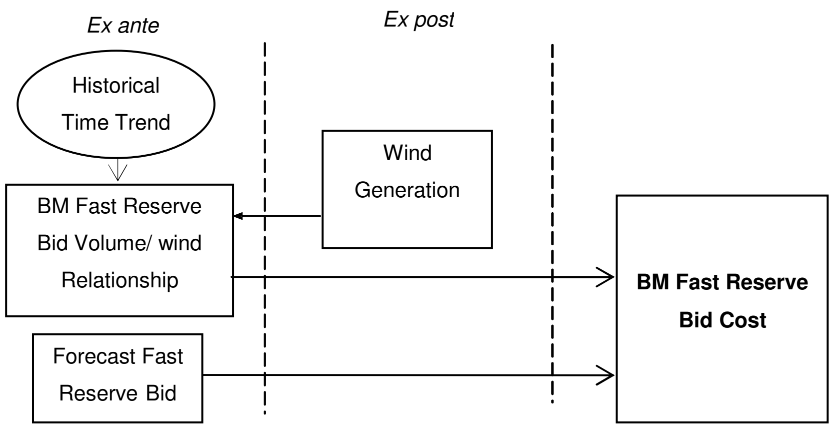
(b) BM Bid price regression on coefficients: Average SPNIRP volume and Trend;

(c) BM Offer volume regression on coefficients: Average Winter Wind volume and Trend;

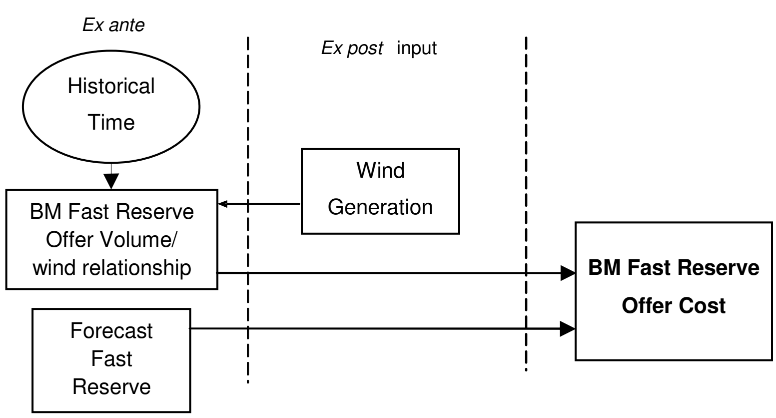
(d) BM Offer price was a fixed number based on history; and

(e) AS costs regression on coefficients: Average Wind volume, Average SPNIRP volume, Average Winter SPNIRP volume and Summer.

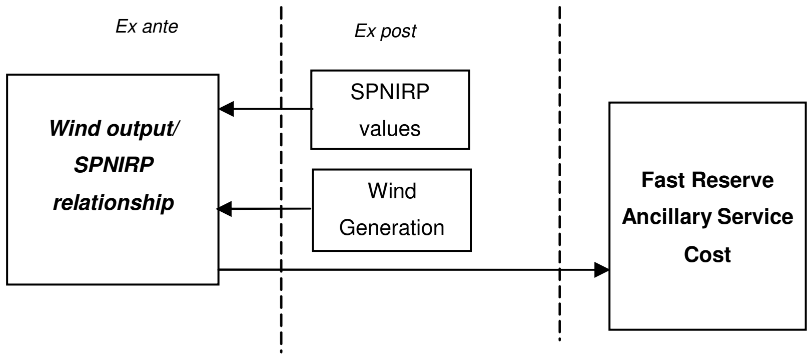
The BM Fast Reserve Bid cost model



The BM Fast Reserve Offer cost model

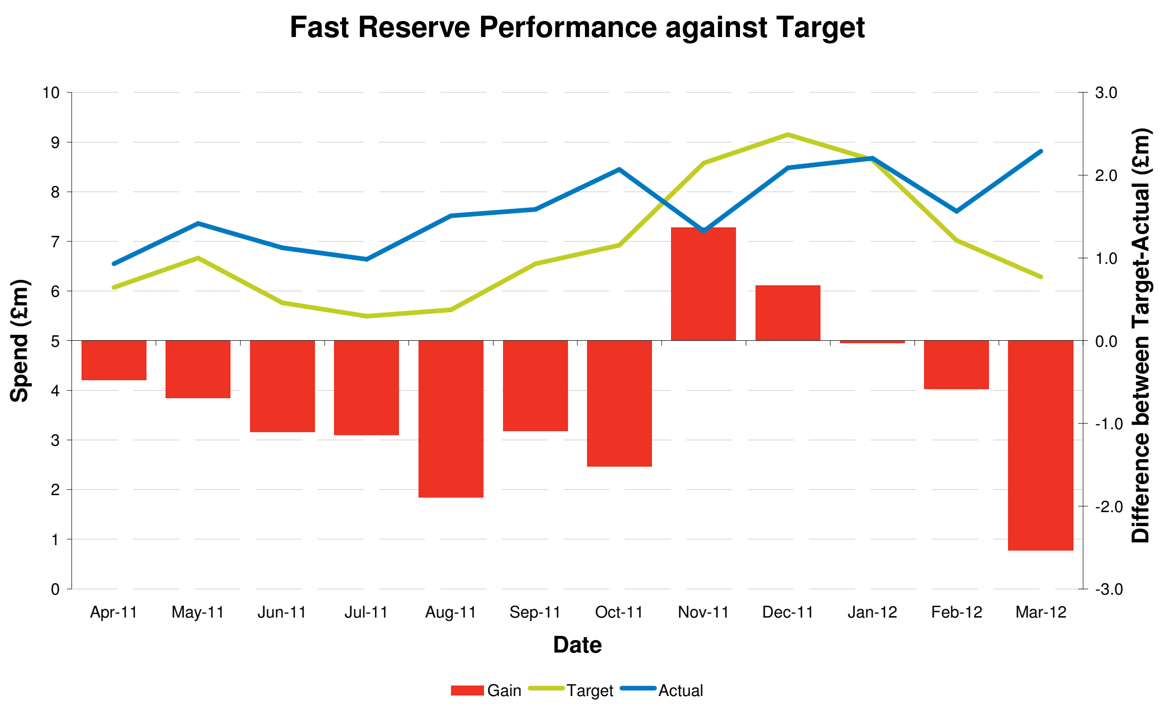


The Fast Reserve Ancillary Services Model



Model Performance

A50 Over the course of 2011/12 the outturn costs were closely aligned to the model forecasts where we spent £91.8m against a target of £82.8m. The performance of the model is shown in the graph below.

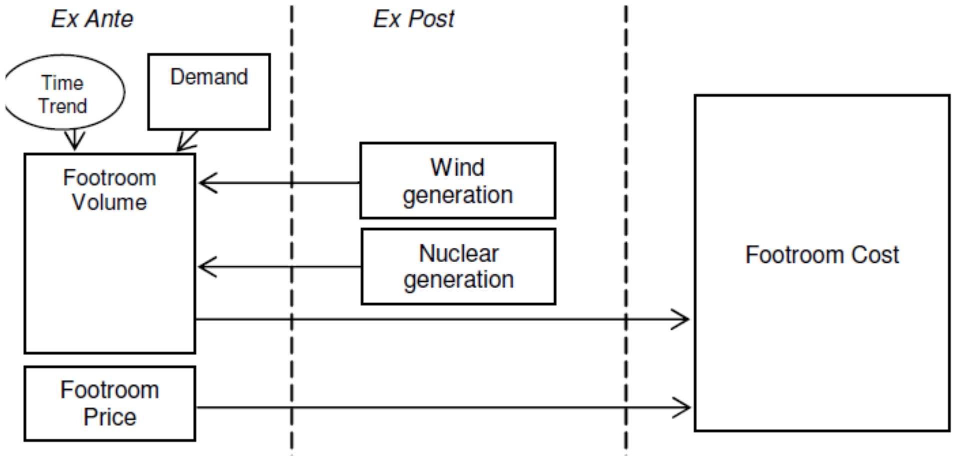


Footroom

Current Model and Coefficients

A51 The Footroom target cost model derives Footroom costs from the multiple of a Footroom Price and an estimated Footroom Volume. Footroom price is an ex ante forecast fixed value reflecting the typical historical price of Footroom actions. Footroom Volume is estimated by an Ex Ante regression driven by Ex Post inputs of wind and nuclear generation volumes.

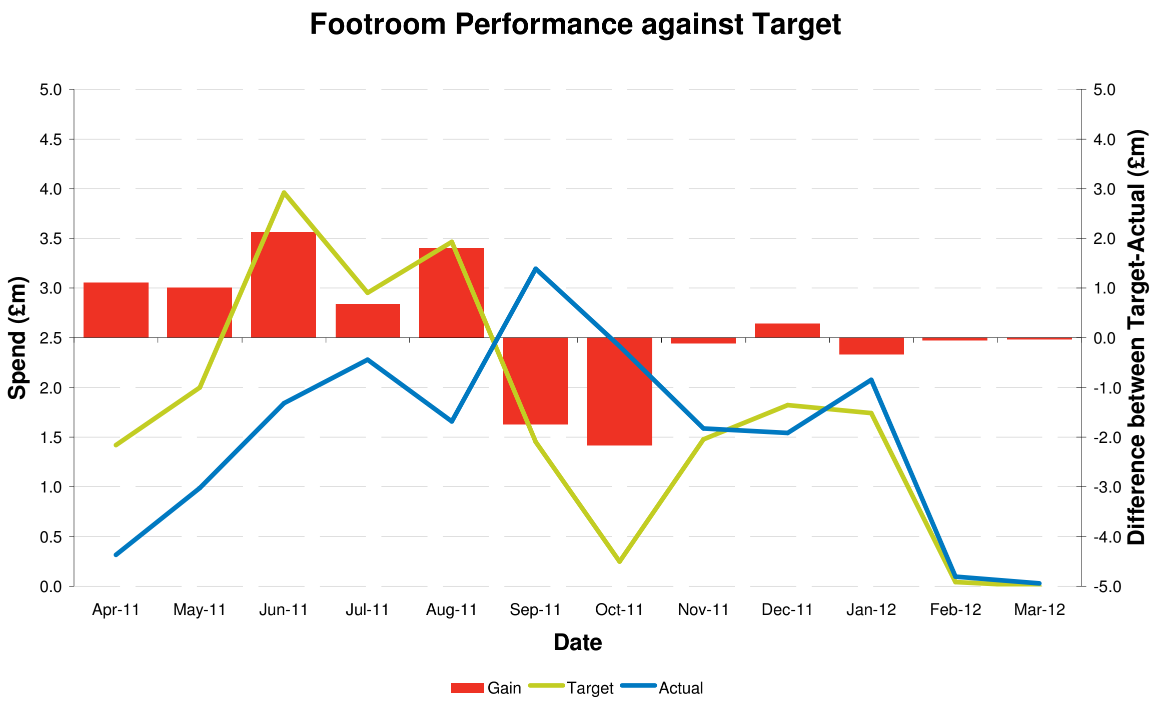
Footroom Cost Model



Model Performance

A52 The ex ante price forecast for the latest year is under forecasting the price of footroom actions whilst the volume forecast is overforecasting the volume.

A53 While over the course of the year the model provided a reasonable fit against actual spend there were net gains and losses in any given month. Performance of the model is shown in the graph below.



Reactive Power

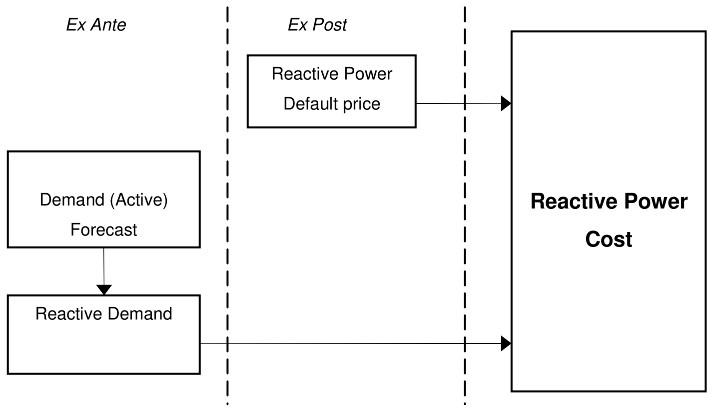
Current Model and Coefficients

A54 The Reactive Power model forecasts the cost Reactive Power from the multiple of a forecast reactive demand (in MVarh) and an assumed ("default") price of reactive power.

A55 Reactive demand is forecast ex ante as a proportion of active-demand forecast (absolute i.e. regardless of sign) and this is based on historical experience (over the period 2009-2011).

A56 Reactive Power price is forecast using ex post RPI and wholesale electricity price inputs (in accordance with the CUSC, Schedule 3 reactive power default price calculation).

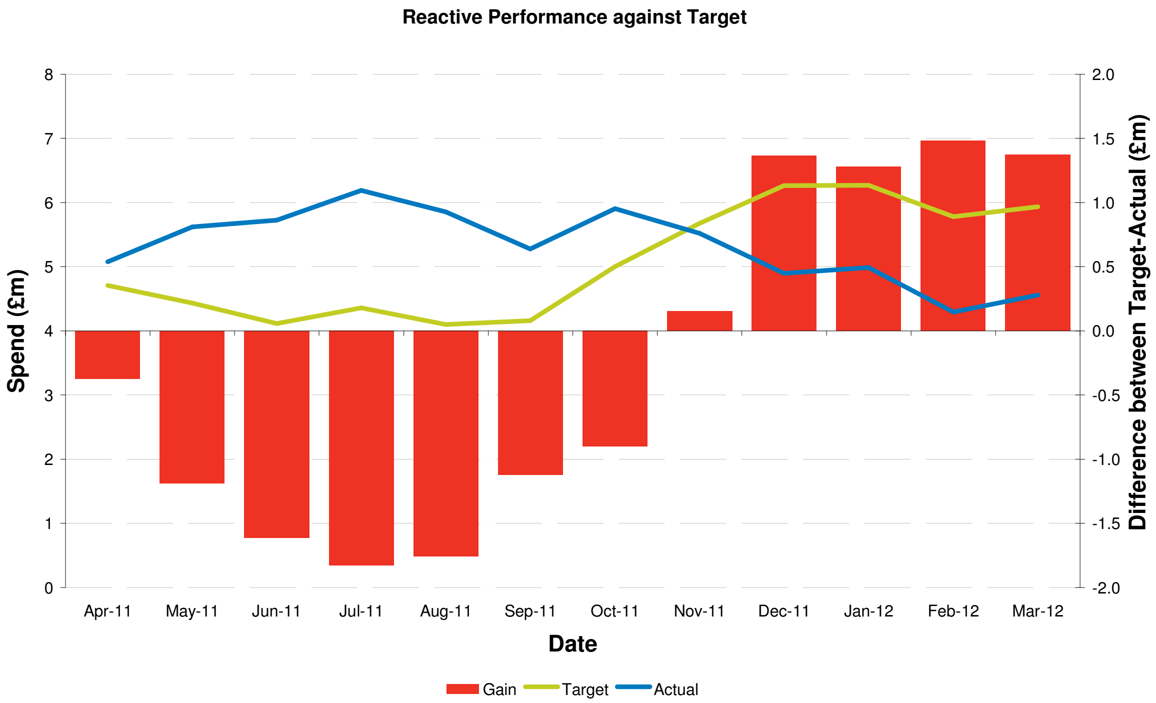
Reactive Power Cost Model



Model Performance

A57 Throughout the summer months we spent more on reactive management than was forecast in the model, this is largely driven by the characteristics of the synchronised generation and outages on the transmission system requiring an increase to the volume of voltage related actions.

A58 This model has returned a relatively balanced outturn over financial year 2011/12. The largest monthly gain was £1.5m during period April 2011 to October 2011, whilst the largest monthly cost was £2.7m during period November 2011 to March 2012. The performance of the model is shown in the graph below.



Appendix B: Constraint Model - supporting information

Overview

B1 This appendix sets out further detail to the 'Constraints Modelling' section with regard to the rationale for not pursuing the full nodal model within the Constraint model which has led us to further develop the current model for the purposes of the RIIO-T1 incentive period. It also sets out how BM price is currently treated within the model and the further analysis that we have undertaken to forecast BM price on an ex ante basis.

Challenges with Developing a Full Nodal Model

B2 As part of the Supplementary Review, we agreed with Ofgem to investigate the feasibility of implementing a full nodal network model (also known as the 'enduring solution'), that would be capable of determining constraint boundary limits for itself. The objective of this was to have an independent means of identifying constraint boundary limits on an ex ante basis rather than being determined by National Grid as they are currently. The intention was to use existing functionality in the Constraint model and also work in conjunction with the Constraint model software developer, to incorporate additional functionality to enhance constraint modelling capability.

B3 The Constraint model already had the functionality to import a single state network model, for the purposes of running a DC load flow analysis. However, this in itself cannot determine what constraint limits should be as it takes no account of NETS SQSS operational standards that oblige us to secure the system for fault outages. Furthermore, it cannot perform AC or complex stability studies that are required to assess voltage and stability conditions.

B4 Furthermore, it was recognised that in the absence of an AC capability, it would not be possible to derive constraint limits in their entirety and there would have to be some additional boundary overlay capability of rules based inputs to cater for voltage and stability constraints.

B5 In order to derive the thermal constraint limits, it was necessary to incorporate a contingency analysis capability. This was a development required from the software developer to enable the Constraint model to simulate fault outages and assess power flows against available remaining capacity. Through this process, boundary limits could thus be derived.

B6 We were successful in incorporating a full network model and contingency functionality into the model, however two issues arose which brought such an approach into question; computational complexity and limitations in the representation of the network model.

B7 The computational complexity of the model is described in the table below. This details the number of calculations the model would be required to execute for a given number of contingencies. This provides a measure of the additional complexity a full contingency analysis would introduce over and above the existing model.

Constraint model Complexity Analysis

Option	Measure of Complexity	Complexity Score
Model with full contingency analysis	1300 x 2836 x (365 x 48)	64,592,736,000
Run 1300 contingencies and monitor all lines 2 periods (1B & 3C/DP)	1300 x 2836 x (365 x 2)	2,691,364,000
Run 1300 contingencies and monitor all lines, 4 periods per week (1B & 3C/DP) x Thursday & Sunday	1300 x 2836 x (52 x 4)	766,854,000
Manually Created Boundaries	2836 x (365 x 48)	49,686,720
Constraint model created Boundaries	2836 x (365 x 48) + 1300 x 2836 x 100	283,686,720
Existing BSIS Scheme	47 x (48 x 365)	823,440

B8 The level of complexity associated with a full contingency analysis (64,592,736,000 calculations compared to 823,440 within the current model) led to model run times that were deemed too excessive (50 hours+) and even a significant reduction in the number of contingencies and monitored lines resulted in long run times.

B9 However, the more fundamental issue is that the Constraint model is only able to hold one single state network configuration. The ability to reflect the appropriate system status (e.g. different switching arrangements) is critical to deriving an accurate forecast target cost. In the prototype model we used a representation of the system from a peak winter day. However, during other times of the year, extensive changes to substation running arrangements are required to accommodate circuit outages and changing fault levels. The tests that were performed on the model provided a cost profile that we deemed of an unrealistic magnitude, mainly because upon running contingencies, generators became isolated from the network or circuits became severely overloaded. In reality many of these costs would be ameliorated by changes in system configuration.

B10 In light of these complex issues and software functionality limitations we, with agreement from Ofgem, suspended development of the full nodal modelling approach. We have therefore looked to make enhancements to the model employed for the current BSIS for application to a multi-year incentive framework under RIIO-T1.

Costing Constraints – current treatment of BM Price

B11 The BM prices used in the constrained run are derived for four pricing bands, using the volume weighted average bid or offer price per half hour, per BMU, with respect to the prevailing capped physical notification[84] (CPN). The offer and bid prices for each BMU are defined in respect to the following modes of operation:

(a) Energy Bids - the submitted bids on a unit to reduce its output from Final Physical Notification towards Stable Export Limit (SEL). The expectation would be that the price reflects the value of the fuel saved (or the value of the Renewable Obligation Certificate (ROC) for renewable generation);

(b) Energy Offers - the offers on a synchronised unit above SEL. The expectation would be that the price reflects the cost of fuel used;

(c) Desynchronising Bids - the submitted bids on a unit to reduce its output from SEL to zero. The expectation would be that the price reflects the value of the fuel saved, and also the cost of increased maintenance due to increased start-ups; and

(d) Synchronising Offers - the submitted offers on a unit to switch the unit on and increase its output to SEL. The expectation would be that the price reflects the cost of fuel used and the maintenance cost due to the synchronisation event.

B12 Full methodology details of the above approach are described in *The Statement of the Constraint Cost Target Modelling Methodology*[85].

Additional investigations into forecasting BM price submissions

B13 At Ofgem's request, as part of the Supplementary Review, we have undertaken further analysis to investigate whether there are additional explanatory variables with which to model BM prices on an ex ante basis.

B14 The approach taken to this analysis was the use of Ordinary Least Squares (OLS) regression analysis. This technique assumes each time slice is independent, and the history of each variable is unimportant. OLS has proven very useful in forecasting national demand at longer lead times, and is a very robust modelling tool.

B15 Through the analysis carried out for the current scheme, it was apparent that attempting to model BM prices through evaluating the full range of bid/offer pairs was unlikely to provide satisfactory results. The five bid/offer pairs that balancing mechanism participants submit will often be related to different elements of their cost structure for which, the required transparent explanatory variables are not available.

B16 Rather than use all bid / offer pair IDs, the analysis used only the first bid/offer pairs (-1 for bids and 1 for offers[86]) i.e. those bids or offers that reflect the price of deviating from the original submitted physical notification.

B17 Adopting this approach should increase the strength of the relationship that the input data provides as further bid/offer pairs tend not to be used in any meaningful sense[87].

[84] CPN which is defined as the minimum value of the final physical notification and the maximum export level

[85] http://www.nationalgrid.com/NR/rdonlyres/32C1D8DC-D7AB-4C8B-950C-FBBB28A3975B/47900/Constraints_Modelling_Methodology_Issue1_18July2011_Final.pdf

[86] Therefore the +1 offer submission is not the offer associated with unwinding the -1 bid, but that for increasing output from submitted final physical notification (FPN)

[87] This is by definition in that additional bid offer pairs are less attractive and therefore any spikes in pairs 1 & -1 will also be reflected in subsequent bid offer pairs (as they have to be monotonically increasing or decreasing)

If a model is possible, the fundamentals of it should be demonstrated in the first pair as they tend to have the most volume associated with them.

B18 To further improve the chance of isolating explanatory variables, the focus of the analysis was carried out on coal-fired and gas-fired (including OCGT) BMUs; as the majority of all BM actions executed by National Grid will be enacted on these units. Whilst both hydro plant and wind is used in the BM it tends to be for very small volumes. Due to their technological limitations, the current nuclear fleet does not actively participate in the BM; likewise CHP units tend not to participate because of their associated heat provision obligations.

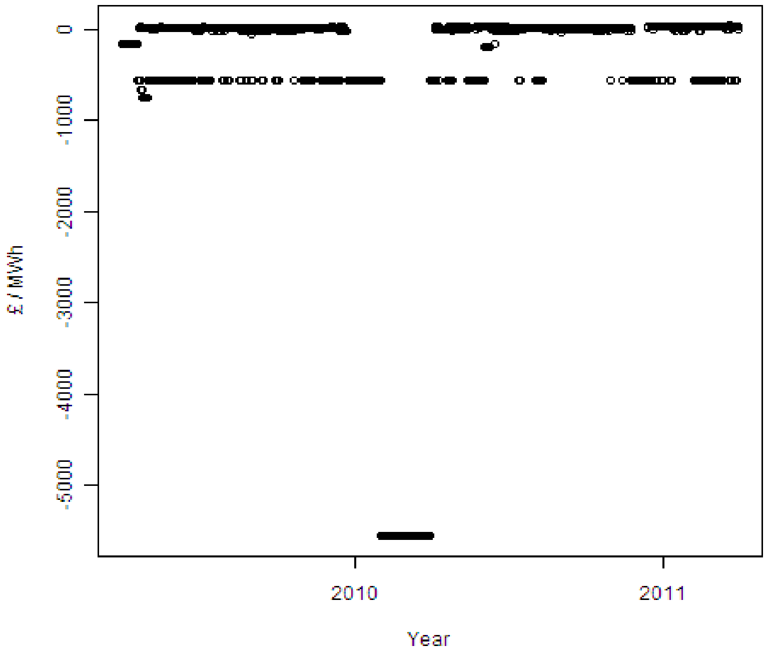
B19 For the purposes of our analysis, we used two years of historic data in order to maintain consistency with the data that we intend to use in the calibration of the enhanced network model. The time range chosen was April 2009 to March 2011 inclusive.

B20 The dataset of submitted BM prices does contain outliers i.e. occasionally price levels may be several orders of magnitude higher than the underlying mean level. As the intention of the analysis was to identify the fundamental correlations to price submission, it was necessary to remove these outliers from the dataset, through a filtering process.

B21 The data was first filtered to remove what can be termed “extreme” BM prices. This issue is illustrated in the following figures, both of which provide an example of the issue for a bid and offer pricing structures for two BMUs.

B22 The figure below suggests that the BMU tends to submit bids within a number of pricing bands. There is a clear difference between those bid prices that would appear to reflect an economic level, from a system operator perspective and those that are priced at a significantly higher order whereby an economic rationale could be harder to determine.

Coal-fired BMU: First order (-1) bid price £/MWh



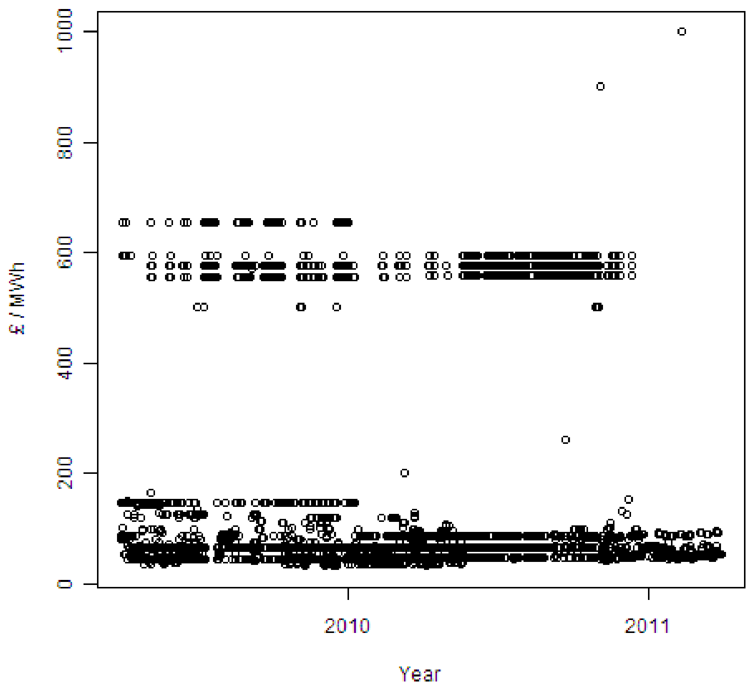
B23 It should be recognised that a negative bid price may not in itself be uneconomic as it may reflect lost opportunity in respect of revenue, represent a short term technical limitation, or alternatively it may mirror the pricing behaviours of other competing BMUs. However there is a floor level where it can be inferred that economic drivers are not the basis of price formulation.

B24 In respect to this BMU a distinction can be drawn between bid price values greater than or equal to -£190/MWh and those less than -£190/MWh. Across the 9991 half hour periods where bid price exceeded this threshold, there were only four different values submitted.

B25 Indeed 99% of bid price submission in excess of the -£190/MWh threshold were either -£5555/MWh or -£555/MWh. Price submissions at this level are unlikely to result in an acceptance and therefore the inference drawn is that active participation in the BM is not a primary consideration to the BMU owner.

B26 Other BMUs demonstrate a similar approach to their pricing strategies. The figure below illustrates such, but this time on offer price submission.

Coal-fired BMU: First order (+1) offer price £/MWh



B27 In this instance, two pricing bands appear to dominate, with a threshold level of approximately £400/MWh. Though it is unlikely that values in excess of this threshold would be economic, it is possible that this pricing structure reflects system conditions at different times, however the nature of the distribution would suggest this is not likely to be the case. However, it does illustrate the challenge in identifying and modelling relationships where a small number of data can skew and obscure any fundamental relationships.

B28 The filtering approach adopted for this analysis is designed to capture observations where a generator's output is at a level conducive to taking an active role in the balancing mechanism.

B29 Therefore, in respect to bids, the filter selected only those bid prices that were greater than or equal to zero and with a PN>SEL.

B30 For offers, the filter selected only those offer prices of less than £500/MWh, with a PN greater than zero and a PN less than MEL. This is summarised in the table below.

Filter approach to bid and offer data from analysis

Bid Filter		Offer Filter	
	Price ≥ 0		Price ≤ 500
AND	PN > SEL	AND	PN > 0
		AND	PN < MEL

B31 For clarity, if the BMU data meets the requirements of the filter in any half hour period, then it is retained; otherwise it is not used to fit the model.

Variable modelling and measures of fit

B32 We identified eight specific variables[88] that we wanted to test for explanatory power.

These were:

(a) Fuel type – is there evidence of a difference of approach in pricing strategies of different fuel types across the fossil portfolio;

(b) Fuel price – does the price of the primary fuel have a significant impact on pricing strategy;

(c) Carbon price – does the price of carbon have a significant impact on pricing strategy;

(d) Short run marginal cost (SRMC) – to test the current methodology for ex-ante BM pricing and to determine if any other variables that contribute to SRMC definition;

(e) TNUoS – to determine if transmission charges have any impact on BM price formulation;

(f) System Demand – does the level of demand have any influence;

(g) Seasonality – is there a structural or seasonal pattern to price formulation; and

(h) Large Combustion Plant Directive (LCPD) – is there evidence of a difference in pricing strategy between BMUs that opted not to fit FGD.[89]

Analytical approach

B33 The approach taken to the regression analysis was two-fold. The first was to explicitly regress against each variable identified previously and secondly we allowed the model to self-select the best explanatory variable for each bid and offer by BMU, i.e. choose the variable that gave the best R^2 or Root Mean Squared Error (RMSE) value.

B34 We also investigated whether it was possible to identify an opportunistic element to pricing. In order to do this, we allowed the model to regress against each individual variable to a power 1 through 3 in increments of 0.1. For example:

$$\text{BM price}_i = \alpha + \beta \times \text{fuel price}_i + \varepsilon_i$$

$$\text{BM price}_i = \alpha + \beta \times \text{fuel price}_i^{1.1} + \varepsilon_i$$

---

[88] As identified in supplementary licence condition AA5I.

[89] LCPD – Large Combustion Plant Directive – if a unit opted out of the directive they were limited to 20,000 hours of generation between 2008 and 2015.

$$BM\ price_i = \alpha + \beta \times fuel\ price_i^{1.2} + \varepsilon_i$$

And so on, until and including

$$BM\ price_i = \alpha + \beta \times fuel\ price_i^{3} + \varepsilon_i$$

B35 So, if gas price was a good explanatory variable, this approach may improve the explanatory power of the variable against those BM prices further away from the mean (e.g. if fuel price$(x)^2$ doubled then bid or offer price would change by a factor of 4). This approach follows the principle that pricing behaviour is driven from an underlying fundamental, and should be measured in the same underlying unit of measurement (fuel price). It should be noted that for an ex ante forecast to be achievable then this hypothesis must stand.

B36 The table below provides an example of the results that were achieved for those BMUs where their bid and offer price submissions were best explained by the price of their primary fuel source. It also includes the error results for those BM prices that are best explained by a variable other than its primary fuel source.

Bid and Offer Errors £/MWh

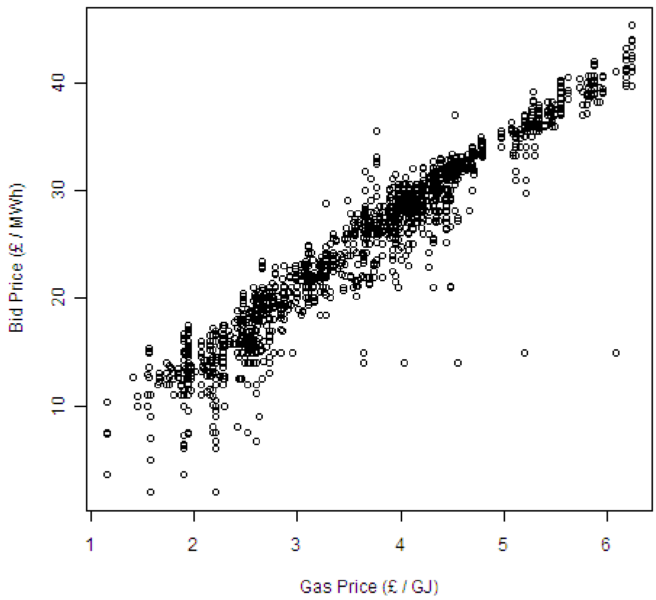
Variable	MAE		RMSE		Bias		R2	
	Bid	Offer	Bid	Offer	Bid	Offer	Bid	Offer
Primary Fuel Source	2.39	12.23	3.99	18.07	0	0	0.82	0.47
Other Single Variable	3.33	17.45	5.19	30.11	0	0	0.67	0.35

B37 It is apparent from the results that in all cases, bid prices are comparatively better explained by one of the variables than those for offers. In respect of each error measure, the explanatory power is greater for bid price forecasting in comparison to offer price forecasting.

B38 In respect of selecting whether any of the variables carry sufficient explanatory power, in the first instance, we need to consider the R^2 value. As a value of 1 would mean that the variable explains the BM price perfectly, a value closer to 1 is better. The scatter plots below demonstrate the fit of the model against a BMU with a high R^2 and one with a slightly poorer R^2.

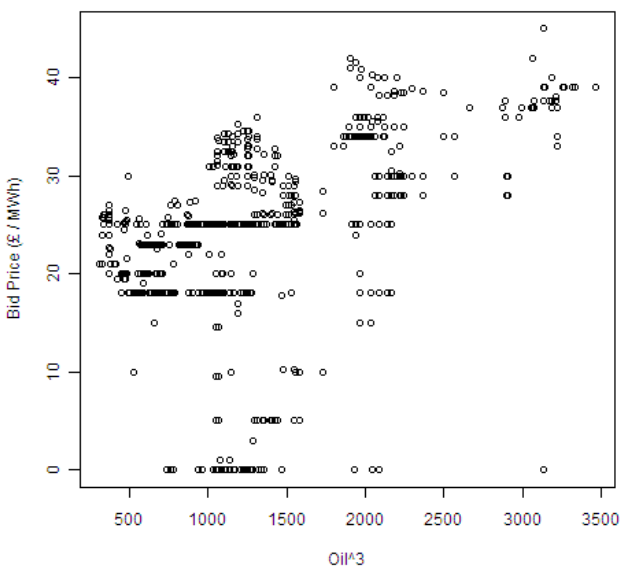
B39 In the figure below, the first BMU has a bid price, whose variation is best explained by its primary fuel source, which in this case is gas. This has an R^2 value of 0.94 and the scatter plot demonstrates the change in bid price with the change in the underlying price of the fuel.

Scatter graph of BMU with high (0.94) R^2 value



B40 In contrast to the previous example, the graph below represents a BMU whose variance in bid price is better explained, but to a lower level, by a variable that is not its primary fuel source. In this case the BMU is a coal-fired unit, but the variable with the most explanatory power is oil price$^{\wedge 3}$. In this instance, the R^2 value is 0.45.

Scatter graph of BMU with lower (0.45) R^2 value



B41 However in respect of providing a suitable basis for an ex-ante forecast it is not obvious what the impact may be. Therefore we can provide an indication of the monetary impact by taking the RMSE (£/MWh) for each variable and applying this to the constraint volume. This is examined later in this document.

Summary Results for variables (fuel price, fuel type and carbon)

B42 As noted above, we performed regression analysis with a number of variables to identify which of them was best in terms of explanatory power, allowing the model to test all of the variables for explanatory power and selecting the appropriate variable.

B43 We identified stronger relationships within the bid price submissions than the offers and fuel price was by far, the variable that provided most explanatory power in respect to bid prices. The best variable for offer prices varied and only a limited number of BMUs had fuel price as best variable.

B44 As previously indicated, we ran the analysis on coal and gas-fired BMUs only, as they are typically the most flexible generation technologies and the most likely to reflect pricing strategies that are linked to a fundamental, such as fuel input costs. As the two technology types dominate the generation portfolio, any results derived are likely to be more representative.

B45 In total we considered 119[90] BMUs, of which 53 were gas and 59 were coal. The results in the 'Bid and Offer Errors £/MWh' table above are for those variables that can be regressed against in their raw form i.e. there are no adjustments made to the underlying data, for example efficiency etc.

Single variable regression results

Variable	No. of units where variable has most explanatory power		Highest R2 where variable has most explanatory power		Lowest R2 where variable has most explanatory power	
	Bid Price	Offer Price	Bid Price	Offer Price	Bid Price	Offer Price
Fuel price & type	82	6	0.94	0.32	0.03	0.28
Carbon	3	3	0.29	0.12	0.27	0.06
Demand	1	8	0.35	0.28	N/A	0.13
Other	37	95	0.81	1.00	0.32	0.04

B46 As expected, it is evident that fuel price is an important variable for determining the bid price in over two thirds of the BMUs. As indicated in the table below, gas fired units tended to price against fuel costs slightly more than coal-fired BMUs. There may be numerous reasons for this, although the gas market provides greater

[90] Due to the filtering process, only 112 BMUs provided results for bid prices and 115 for offer prices

opportunity to price flexibly due to the liquid market and the “just in time” nature of delivery.

Breakdown by fuel type – fuel best explanatory variable

Fuel Type	No. of units where fuel has most explanatory power		Total no. of units		Percentage of fuel type where fuel has most explanatory power[91]	
	Bid Price	Offer Price	Bid Price	Offer Price	Bid Price	Offer Price
Gas	45	4	53	56	85%	7%
Coal	37	2	59	59	63%	3%

B47 The fact that the same explanatory power does not translate to the offer price to the same extent is not unexpected as offer prices tend to reflect opportunity and prevailing market conditions. Likewise, carbon appears to have limited impact on pricing strategy as it currently has a lower impact on costs in comparison to the underlying fuel.

Summary Results for variables (SRMC, TNUoS, LCPD)

B48 It was agreed to investigate the relationship between Short Run Marginal Cost (SRMC) and bid and offer prices, as this is the means by which we produce an ex ante forecast in the current BSIS scheme. The current scheme applies a scaling factor to SRMC to derive ex ante bid and offer prices. These scaling factors were derived from analysis that provided the best overall fit, rather than one that provided the best fit on a BMU basis.

B49 SRMC is derived through the formula given below:

((fuel price (£/GJ) + transport charge (£/GJ) + (carbon price (£/kg) x production rate (kg/GJ)) x heat rate (GJ/MWh)) + maintenance price (£/MWh)

B50 The current scheme uses SRMCs calculated from coal price at month ahead, and if this is unavailable then quarterly is used; as a last resort yearly are used. The fuel price of gas units is day ahead gas price.

B51 BM prices are a simple function of SRMCs; they are obtained by multiplying SRMC by a fixed number and vary depending upon the operational status of the BMU. There are four types of status, each of which has a different scaling factor applied to reflect the associated cost structures of each operating mode. These options are a de-

[91] This percentage is derived across only those BMUs that provided results for bids and offer analysis

synchronisation bid, energy bid, energy offer or synchronisation offer. The multipliers are given in the table below.

BSIS 2011-2013 SRMC multipliers

Price	Ratio
Desync bid	0.2
Energy bid	0.8
Energy offer	1.4
Sync offer	1.6

B52 The SRMC accuracy per BMU may likely be improved by tailoring the ratios to fit each BMU. This was achieved by taking the ex post submitted bid and offer prices and regressing them on the current SRMCs; The regressions did not have an intercept term that is the following.

B53 As a result of the data filtering process described earlier, the data would reflect only energy bids and energy offers. This process would identify a single co-efficient (α_{BMU}) for each BMU.

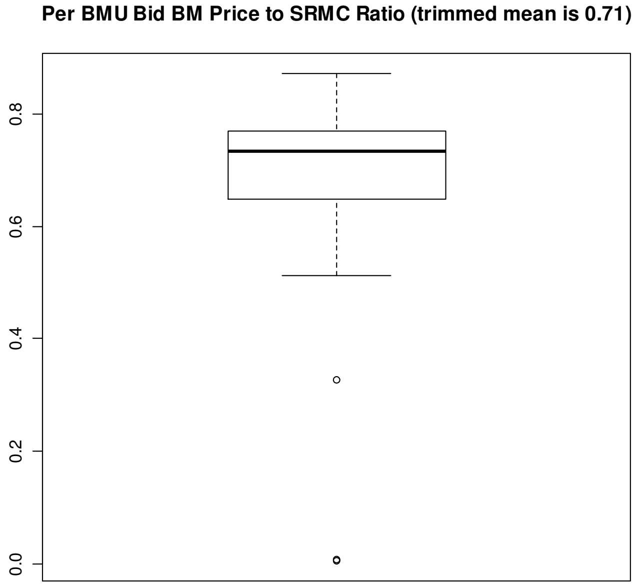
$$\text{BM price}_i = \alpha_{BMU} \times \text{SRMC}_i + \varepsilon_i$$

Where the errors (ε_i) are assumed independent and normally distributed ($N(0, \sigma^2)$).

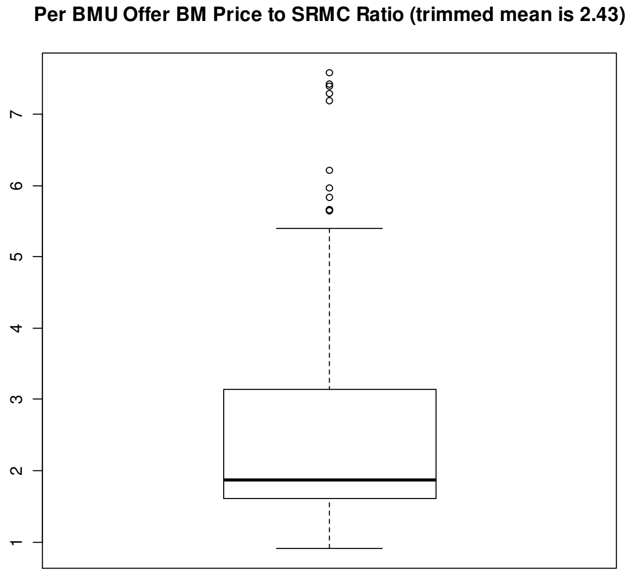
This regression was done for each coal and gas BMU, including OCGTs.

B54 The trimmed mean of all the α_{BMU} was 0.71, which is not too far from the current scaling factor of 0.8 for energy bids. However the modelled scaling factor for the energy offer price is considerably different with a trimmed mean (median) of 2.43. The Figures below describe the range of individual scaling factors for both energy bids and energy offers.

Box plot for energy bid prices[92]



Box plot for energy offer prices



[92] The plots describe the median or P50 value (dark line) with the 25th and 75th (interquartile range) centile limits described by the box. The outermost lines extend to 1.5 times the interquartile range from the box, thus capturing the majority of the data. The two dots represent a few extreme outliers.

B55 This approach identified that the ex ante forecast could be improved by training the model on each BMU submitted balancing mechanism price submissions. The table below provides a basis for comparing the different approaches to modelling of SRMC.

Error statistics (£/MWh) for BSIS 2011-2013 and tailored SRMC.

Model Approach	MAE		RMSE		Bias		R2	
	Bid Price	Offer Price	Bid Price	Offer Price	Bid Price	Offer Price	Bid Price	Offer Price
BSIS 2011-13 scaling factor	4.53	26.63	7. 60	43.95	3.19	-22.32	0.37	-0.38
Tailored coefficients	3.21	21.41	5.40	33.61	0.36	-2.07	0.68	0.19

B56 It is clear that the tailored co-efficient approach provides for a much better model than the current scaling factors for energy bids and offers.

B57 There are many potential cost drivers that may determine the pricing strategies of BM participants. Thus far we have focused on the short term variable cost drivers; however it could be possible that long run cost recovery also makes up a component of BM pricing.

TNUoS

B58 One such longer term cost is the TNUoS charge. This consists predominantly of a charge[93] to generators to reflect the cost of providing transmission routes from generation to the centres of demand. It is charged on an annual basis and therefore can be viewed as a long run marginal cost.

B59 We were interested to see if those generators that have a higher TNUoS charge reflect this in their BM pricing behaviour. The TNUoS charge is paid on the basis of generation and demand. For generation, it is charged against Transmission Entry Capacity (TEC) and therefore is a sunk cost each year. Charges for demand are based on metered off-take over TRIAD periods. The exceptions to this charging basis are those generators in negative TNUoS charging zones. These negative zones reflect the significant benefit of locating generation in particular areas of the country where there are high demand levels and low generation capacity.

B60 Therefore a generator can possibly reduce their demand TNUoS charge by reducing output over the triad period, although it is not a linear relationship between output and station demand. However, plant with FGD may offer more attractive bids for example, with the aim of reducing output and reducing demand.

B61 A generator in a negative zone pays (in this case receives a payment) on the basis of metered output. Therefore, if the generator is not running at full output, there may be an incentive to reduce offer price to encourage the NETSO to accept an offer and

[93] There are some generators' that pay a negative TNUoS charge (receive a payment)

increase output and corollary submit less attractive bid prices in order to deter bid acceptance.

Incentives on output or demand for generators in different charging zones.

	Demand	Generation
Negative Generation TNUoS Tariff	Neutral[94]	Maximise
Positive Generation TNUoS Tariff	Reduce	Neutral[95]

B62 Triad periods will occur within the period November to February, and across the settlement periods 31 to 38 as the highest demands will occur over these periods. Therefore in order to identify if there is a significant change in pricing behaviour over these periods, we examined the ratio of submitted BM prices during settlement periods 31 to 38 over November to February against all other periods in the same season (November to February). This ratio is described as

$$\frac{\text{mean(Nov} - \text{Feb and period } 31 - 38 \text{ prices)}}{\text{mean(Nov} - \text{Feb and period} < 31 \text{ or} > 38 \text{ prices)}}$$

B63 It was also important to check the ratios outside of the triad periods to check if there was any significant difference in pricing behaviour. The following ratio was also calculated for each BMU

$$\frac{\text{mean(Nov} - \text{Feb and period } 20 - 30 \text{ prices)}}{\text{mean(Nov} - \text{Feb and period} < 20 \text{ or} > 30 \text{ prices)}}$$

B64 Finally, we calculated the ratio of prices for periods 31-38 for months that fall outside of the triad charging period i.e. March to October.

$$\frac{\text{mean(Mar} - \text{Oct and period } 31 - 38 \text{ prices)}}{\text{mean(Mar} - \text{Oct and period} < 31 \text{ or} > 38 \text{ prices)}}$$

B65 These ratios were calculated on an annual basis and were then regressed against the TNUoS[96] charge for each BMU and results analysed for explanatory power of TNUoS for the bid and offer prices in each period described above.

B66 The table below provides the R^2 values for the regression of TNUoS against bid and offer price for a selection of BMUs. These have been selected as they have the higher, but not necessarily sufficient (in respect of explanatory power) R^2 values for the peak period defined above and demonstrate a significant difference against the

[94] Generation maximisation takes precedence over demand reduction
[95] Based on TEC
[96] TNUoS is charged on a station level. Therefore stations with more than one generating unit, the charge was adjusted to a per unit basis.

periods defined in above. However they also have significant variance in the R^2 values across the generation units on the same site and from a broad range of geographical locations.

Regression of TNUoS against summer winter bid ratio

BMU	Nov-Feb Periods 31-38	Nov-Feb Periods 20-30	Mar-Oct Periods 31-38
[Text Deleted]	0.70	0.45	-0.24
[Text Deleted]	0.53	0.12	0.06
[Text Deleted]	0.59	0.32	-0.04
[Text Deleted]	0.17	0.55	-0.25

.

Regression of TNUoS against summer winter offer ratio

BMU	Nov-Feb Periods 31-38	Nov-Feb Periods 20-30	Mar-Oct Periods 31-38
[Text Deleted]	0.39	0.03	0.42
[Text Deleted]	0.37	0.01	0.50
[Text Deleted]	0.89	0.65	-0.24
[Text Deleted]	0.60	0.08	0.23

B67 The analysis does not provide any conclusive results. Where higher R^2 values have been observed, there is not sufficient consistency across similar units at the same site to conclude any definitive relationship with TNUoS. This leads to the conclusion that there is no formulated strategy in respect of reflecting TNUoS costs in BM prices

LCPD

B68 LCPD opted out units have only 20,000 hours of generation available to them across the period 2008-2015. Therefore, we wished to explore whether LCPD opted out units displayed different pricing behaviours to BMUs that are LCPD compliant (opted in).

B69 Our hypothesis was that opted out plant would aim to generate in the highest value periods (winter months). Therefore, if they are to be made available during summer months, we would expect to see a difference in BM price submissions to those made in winter, reflecting the fact that hours used in the summer will be lost to the potentially higher revenue winter periods.

B70 The LCPD opted out BMUs were identified and then paired to another BMU that is LCPD compliant. The pairing was made on the basis of similar heat rates (and hence theoretically should have similar marginal cost) and approximate size.

B71 We conducted the analysis over two definitions of the winter period, December to February (to isolate the peak winter demand months) and October to March. The extended period was studied in recognition that there is a higher likelihood of tighter plant margins in the TRIAD period that may influence pricing behaviour. Looking at the wider period would dampen the impact of tighter margin days.

B72 The figures below show the bid and offer price ratio between summer and the December to February winter period.

B73 In respect to bid prices, it can be seen that the opted out BMUs (represented by the red columns) are well dispersed across the fossil-fired portfolio with bid prices tending to be lower in the summer than the winter. There appears to be no significant difference to the comparator (LCPD compliant) BMUs (represented by the yellow columns). This may reflect the typically lower cost of fuel in the summer.

Summer: Winter bid price ratios

[graph deleted]

Summer: Winter offer price ratios

[graph deleted]

B74 In terms of offer price ratio, again there does not appear to be a significant difference in opted-out plant with their comparator BMUs, however there appears to be a more stable approach to pricing between summer and winter offers (i.e. the ratio is closer to 1) for a greater number of the opted-out sets.

B75 Further work is required to understand if the pricing strategies are linked to the number of hours available to the BMUs or station until 2015. As the hours limit is aligned to emissions through the chimney stack rather than on a BMU basis, we would expect to see evidence of "clustering" of BMUs sharing a chimney stack. There are clearly some BMUs that appear isolated from their sister units. This may suggest that the hours limitation is not an operational constraint any longer, perhaps reflecting a strategy of capturing some opportunity runs during the summer when competitor plant is on outage.

B76 Further work is required through a regression analysis of summer/winter price ratios against cumulative hours used and remaining. This will be carried out in the coming weeks but is not yet available at this time of publication.

Seasonality

B77 Further work needs to be carried out in respect to seasonality effects on BM prices. Whilst the ratio analysis carried out as part of the LCPD analysis has suggested there is a difference in pricing between summer and winter periods, it is not conclusive in that it is not clear if the differences are a function of underlying fuel price changes or market conditions.

Cost Impact

B78 When considering whether it is appropriate to use any of the variables identified in this analysis, the likely impact on modelled costs should be considered.

B79 We can do this by applying some of the metrics (errors) identified in the analysis to accepted bid and offer volumes associated with constraint actions. Taking the MAE or RMSE for a variable and multiplying through the bid and offer volumes taken for a constraint, we can arrive at an estimate of the monetary significance of introducing a modelling error.

Bid and Offer Constraint Volumes MWh

Year	Bid volume for constraints	Offer volume for constraints
2010/11	-3,209,620	408,489
2011/12	-4,209,061	1,564,542

Bid and Offer Error Values £ MWh

Variable	MAE		RMSE		Bias		R2	
	Bid	Offer	Bid	Offer	Bid	Offer	Bid	Offer
Primary Fuel Source	2.39	12.23	3.99	18.07	0	0	0.82	0.47
Other Single Variable	3.33	17.45	5.19	30.11	0	0	0.67	0.35

B80 We arrive at the cost in the 'Estimated total cost of error' table (below) by multiplying the volumes in the Bid and offer constraint volumes' table (above) by the error values in the Bid and offer error values' table (above), which contains the error values for regressions against primary fuel source.

Estimated total cost of error – variable = primary fuel source

Primary Fuel	MAE	RMSE	MAE	RMSE
	2010/11		2011/12	
Bid Error Total Estimated Cost (£)	7,670,992	12,806,384	10,059,656	21,845,027
Offer Error Total Estimated Cost(£)	4,99,5820	7,381,396	19,134,348	47,108,360

B81 Likewise the costs in the 'Estimated total cost of error' table are derived by multiplying the errors in the Bid and offer error values' table by the constrained volumes in the 'Bid and offer constraint volumes' table. These errors represent all modelled BMUs, including those whose pricing strategy is better explained by a variable other than the primary fuel source.

Estimated total cost of error – variable = best fit variable

Best Fit Variable	MAE	RMSE	MAE	RMSE
	2010/11		2011/12	
Bid Error Total Estimated Cost (£)	10,688,035	16,657,928	14,016,173	2,1845,027
Offer Error Total Estimated Cost(£)	7,128,133	12,299,604	27,301,258	47,108,360

Summary

B82 Further work will be carried out over the coming months to investigate the possibility of modelling BM prices through a multi-variable stepwise approach. However this is likely to be complex and may need more regular model training within any modelling process.

B83 As a result of the significant error that even the best modelled variables introduce to the constrained costs, it is not appropriate to use any of the variables discussed in this appendix.