NGC System Operator incentive scheme from April 2005

Initial Proposals

December 2004 280/04

Summary

This document sets out Ofgem's Initial Proposals for National Grid Company plc's (NGC) Great Britain (GB) System Operator (SO) incentives which are intended to apply from 1 April 2005.

NGC's existing SO incentive scheme applies to its role as SO in England and Wales (E&W), as have NGC's previous SO incentive schemes. However, the British Electricity Trading and Transmission Arrangements (BETTA) are expected to go-live on 1 April 2005 and from this point NGC will undertake the role of SO across the whole of Great Britain (GB)[1]. Therefore, the SO incentive scheme to be implemented as of 1 April 2005 needs to be developed within the context of NGC's role as GB SO.

The options presented in this document are intended to maintain and, where appropriate, enhance the incentives on NGC to operate the GB transmission system in an economic, efficient and co-ordinated manner. NGC's existing SO incentive scheme was introduced on 1 April 2004 and is intended to run until 31 March 2005. Therefore, a new incentive scheme needs to be put in place from 1 April 2005.

Background

In its role as SO, NGC is responsible for:

- ensuring that the system remains within safe operating limits and that the pattern of generation and demand is consistent with any transmission system related constraints (system balancing); and
- the residual purchasing and selling of electricity to keep the transmission system in balance in real time (electricity balancing).

In carrying out this role, NGC incurs costs for which market participants, and ultimately customers, pay. Ofgem sets incentive schemes covering NGC's SO costs which are designed to provide appropriate financial incentives for NGC to manage these costs within the incentive period. Ofgem sets a target level of costs and, if outturn costs are below this target, NGC keeps a proportion of the reduction in costs as an incentive payment, whereas if costs are above target, NGC bears a proportion of the costs in

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[1] On 1 September 2004, NGC was appointed as the GB SO. See the following DTI press release for details: http://www.gnn.gov.uk/environment/detail.asp?ReleaseID=128201&NewsAreaID=2&NavigatedFromDepartment=False

excess of the target. NGC's overall gains or losses are limited by a cap on payments and a floor on losses. Therefore, NGC's SO incentive schemes are targeted at reducing, on behalf of customers, the costs of operating the transmission system and the costs of balancing real time supply and demand for electricity.

Previous incentive schemes, put in place by Ofgem, have been very successful in reducing the costs of system operation, which customers ultimately face. Between 1994 (when the first incentive scheme was introduced) and 2001, NGC, under the incentives provided by successive schemes, reduced the annual costs of system operation by more than £400 million. Since the introduction of the new electricity trading arrangements (NETA) in 2001, NGC has consistently managed the costs of system operation such that it has outperformed its incentive scheme target. As there have been successive reductions in the incentive scheme target value (Ofgem has reduced the target for the external SO incentive scheme by around £70 million (from approximately £485 million)), this has benefited both NGC in terms of the rewards that it has received under the incentive arrangements and customers who ultimately face the costs of system operation and so benefit from a proportion of the cost savings achieved by NGC.

Initial Consultation

In its September 2004 Initial Consultation document[2], Ofgem recognised that while the geographic remit of the GB SO incentive scheme will increase following the implementation of BETTA, the scope of the existing SO incentive scheme remains appropriate, and should cover all electricity and system balancing costs within the control of the SO.

In terms of the form of the SO incentive scheme, Ofgem stated that the sliding scale mechanism that has been employed since NETA go-live, incorporating an appropriate target level, cap and floor levels, and sharing factors, remains appropriate going forward. Despite Ofgem's preference for symmetrical sharing factors, it is recognised that Scottish system operation costs have not been the subject of incentive arrangements and have not been measured or reported upon as explicitly as in E&W. In the Initial Consultation, Ofgem recognised that this may create uncertainty in relation to the SO costs in the initial period of operation under BETTA, which may need to be reflected in the structure of the GB SO incentive scheme. Ofgem stated that it may be appropriate to consider

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[2] 'NGC System Operator incentive scheme from April 2005, Initial consultation document', September 2004, Ofgem.

developing a deadband, asymmetric floor, cap and asymmetric sharing factors to account for the uncertainty surrounding GB balancing costs.

In terms of duration, Ofgem expressed that it may be appropriate to consider a scheme of two years, and considered that this would be the preferential duration of the scheme. However it acknowledged that BETTA uncertainty may make a longer term scheme impractical.

Most respondents to the Initial Consultation considered that the scope of the GB SO incentive scheme should be those costs which NGC has direct control over. In addition, most respondents considered that, although more pressure could be placed on NGC to drive down costs by lowering the IBC target, the current sliding scale incentive scheme mechanism should be retained.

The majority of respondents considered that it was inappropriate to implement anything other than a one year scheme from 1 April 2005, due to the uncertainty surrounding BETTA. However, several respondents expressed their support, in principle, for longer-term incentive schemes. Respondents who directly commented considered it was necessary to have a contingency plan in the event that BETTA go-live occurs after 1 April 2005, although there was no clear consensus as to the most appropriate approach. Ofgem remains confident that BETTA go-live will be achieved on time.

National Grid Transco (NGT) [3] considered that the scope of its GB SO incentive scheme should be unchanged from that for E&W and that the form of the GB SO incentive scheme may need reconsidering to accommodate the significant uncertainty associated with BETTA. NGT suggested that a deadband and asymmetric cap, floor and sharing factors should not be discounted. In addition, NGT considered that the scheme should be of one year's duration due to the uncertainty of the costs arising under NGC's role as GB SO.

NGT's 2005/06 balancing cost projection

NGT has provided its projections of its Incentivised Balancing Costs (IBC) for 2005/06. As NGC will be responsible for balancing the system on a GB basis from 1 April 2005, NGT's projections cover GB IBC as opposed to just E&W IBC as in previous schemes. Therefore, the balancing costs that are currently internalised within the Scottish

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[3] NGC is the subsidiary of NGT that holds the transmission licence for England and Wales. In this document, references to NGC are only made in respect of licensed activities.

transmission businesses will be revealed under the GB SO incentive scheme. The metrics in the following table illustrate the size of the GB market versus the E&W market.

2003/04	E&W	Scotland	Great Britain	Percentage of E&W
Annual Energy (TWh)	309	34	343	+11.0
Peak Demand (GWh)	54.6	5.9	60.5	+10.8
Generation Capacity (GW)*	61.7	10.2	71.9	+16.5
Generation (TWh)*	305.3	42.2	337.5	+13.8

Notes: *E&W exclude interconnectors.

NGT's projection of IBC for 2005/06 is £543.2 million. This projection is around £128 million higher than the target for the current incentive scheme (£415 million) and is over £148 million higher than NGT's own forecast of E&W balancing costs for 2004/05, which stands at £394.9 million. The overall increase of £148 million consists of approximately £61 million for the move to the GB-wide market under BETTA, just under £56 million associated with constraint costs and just over £31 million as a result of cost pressures on existing activities.

Ofgem's Proposals

Ofgem has carefully considered the views of respondents, including NGT, in developing its proposals. Ofgem accepts the views of respondents that a further one year shallow scheme, based on the existing sliding scale mechanism should be implemented from 1 April 2005. Although Ofgem's preference would be to continue to utilise a scheme with symmetric cap, floor and sharing factors, it is recognised that there is the potential for uncertainty concerning GB balancing costs.

In its forecast, NGT has outlined projected cost increases in light of the risk created by uncertainty concerning GB balancing costs. However, at this stage, Ofgem considers that the proposed cost increases may overstate this uncertainty and associated risk. In light of this, Ofgem considers it appropriate to develop a suite of proposals which provide differing but appropriate balances of risk and reward for NGC. The intention is that NGT can choose from the menu the option that it considers to offer the most appropriate balance of risk and reward.

Therefore, consistent with approach adopted for the NETA go-live SO incentive scheme, in these Initial Proposals Ofgem has developed several incentive scheme options with differing levels of risk and reward. The options presented range from a high risk and high reward scheme through to a low risk and low reward scheme. NGT, therefore, has a range of choices from which it can select what it considers to be the most appropriate balance of risk and reward. In developing these Initial Proposals, Ofgem has sought to develop a range of challenging incentive schemes for consideration which provide an appropriate balance between the need to continue and build on the effective incentives under which NGC has operated in its SO role in E&W to date and the need to reflect any uncertainty associated with the extension of its role to apply GB-wide.

Ofgem's Initial Proposals in relation to the further one year SO incentive scheme from 1 April 2005 are outlined below:

Proposed value[4]	Option 1	Option 2	Option 3
Target	£480 million	£500 million	£515 million
Upside sharing factor	60%	40%	25%
Downside sharing factor	15%	20%	25%
Cap	£50 million	£40 million	£25 million
Floor	-£10 million	-£20 million	-£25 million

As discussed in more detail later in the document, Ofgem is considering changing the treatment of transmission losses within the SO incentive scheme. This entails a move from a gross to a net transmission losses scheme. Ofgem considers that the introduction of a net transmission losses scheme should be considered, as it better reflects the true balancing costs to which the market is exposed.

Ofgem considers that its Initial Proposals strike an appropriate balance between providing NGC a reasonable balance of risk and reward whilst protecting customers' interests by agreeing a proportionate and reasonable target. A more detailed

[4] Monetary values are in money of the day.

explanation of how Ofgem arrived at the proposals and underlying assumptions are set out in the document.

Way forward

Ofgem invites views on any of the issues raised in this document. Responses[5] should be submitted in writing by 21 January 2005. Following consideration of responses, Ofgem expects to publish its final proposals in February 2005 including a statutory notice of Ofgem's intention to modify NGC's transmission licence under section 11 of the Electricity Act 1989 in relation to the proposals contained therein.

[5] All responses will normally be published on the Ofgem website and held electronically in the Research and Information Centre unless there are good reasons why they must remain confidential. Respondents to the consultation should try to put any confidential material in appendices to their responses. Ofgem prefers to receive responses in an electronic form so they can be placed easily on the Ofgem website.

Table of contents

1. Introduction

Purpose of this document

1.1. This document sets out Ofgem's Initial Proposals for National Grid Company plc's (NGC) Great Britain (GB) System Operator (SO) incentive scheme which is intended to apply from 1 April 2005. The proposals presented in this document are intended to maintain and, where appropriate, enhance the incentives on NGC to operate the GB transmission system in an economic, efficient and co-ordinated manner.

Background

British Electricity Trading and Transmission Arrangements

1.2. Ofgem and the Department of Trade and Industry (DTI) are committed to working towards the introduction of the British Electricity Trading and Transmission Arrangements (BETTA) in accordance with the timetable announced by the DTI. Ofgem announced on 18 June 2003 that the target date for go-live would be April 2005 and that the implementation of BETTA required primary legislation. Legal certainty regarding the BETTA proposals was provided following Royal Assent of the Energy Bill on 22 July 2004.

1.3. In a December 2001 consultation document[6], Ofgem noted that one of the principal components of BETTA was the introduction of common independent balancing arrangements across GB, through the creation of a single GB SO that is separate[7] from generation and/or supply interests. NGC was the sole applicant for the role of GB SO and on 17 December 2002, the then Minister for Energy and Construction, Mr Brian Wilson, stated in a response to a Parliamentary Question that, "Licensing of the GB System Operator can not take place until the

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[6] 'The Development of British Electricity Trading and Transmission Arrangements (BETTA) - A Consultation Paper', Ofgem, December 2001.
[7] Other than for the purpose of balancing the system under BETTA, the activity of generation or supply in GB, or of trading electricity in GB, or the carrying out of any other relevant activity which may conflict with the carrying out of the activities of the GB system operator in an independent and non-discriminatory manner, should not be undertaken by the party itself nor by any of its affiliates.

necessary legislation has received Royal Assent. I am minded to accept the recommendation of the GB System Operator Selection Panel that the National Grid Company plc's application for the role of GB System Operator should be accepted[8]."

1.4. On 1 September 2004, the BETTA 'go-active' period began and NGC was appointed as the GB SO[9]. Therefore, as of BETTA go-live, NGC's role as a transmission business will change, as will the roles of the existing Scottish transmission businesses, SP Transmission Ltd (SPT) and Scottish Hydro-Electric Transmission Ltd (SHETL). Since go-active all three transmission licensees have licence obligations to carry out transitional activities in order to prepare for BETTA go-live.

1.5. Until go-live, all three transmission businesses carry out both Transmission Asset Owner (TO) and SO roles in their respective geographic areas. From BETTA go-live, NGC is to retain its TO role within E&W and to carry out its SO role across GB, thereby necessitating the development of a GB SO incentive scheme. SPT and SHETL will retain their own TO roles in their respective geographic areas and relinquish their SO roles to NGC. NGC's roles as TO and SO are discussed below.

NGC's TO role

1.6. In its role as TO for E&W, NGC is responsible for building and maintaining the grid infrastructure in an economic, efficient and co-ordinated manner. NGC's current TO price control is set to apply from 1 April 2001 to 31 March 2006 (however, as outlined later in this chapter, this period is being extended to 31 March 2007). The proposals in this document do not materially affect the allowed revenues defined in NGC's TO price control.

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[8] See Hansard 17 December 2002, Official Report Column 45WS.
[9] See the following DTI press release for details: http://www.gnn.gov.uk/environment/detail.asp?ReleaseID=128201&NewsAreaID=2&NavigatedFromDepartment=False

NGC's SO role

1.7. As discussed further below, the primary responsibility for balancing lies with market participants who have commercial incentives, created by the cash out rules, to achieve energy balance. NGC's role as SO is that of the residual balancer. In its role as residual balancer, NGC, as SO, is responsible for:

- ensuring that the system remains within safe operating limits and that the pattern of generation and demand is consistent with any transmission system related constraints (system balancing); and
- the residual purchasing and selling of electricity to keep the transmission system in balance in real time (electricity balancing).

1.8. System balancing and electricity balancing are discussed further below. Before this, the tools available to NGC for both system balancing and electricity balancing purposes are briefly summarised.

1.9. The Balancing Mechanism provides a tool whereby NGC, as SO, can accept offers of electricity (generation increases and demand reductions) and bids for electricity (generation reductions and demand increases) at very short notice. Bids and offers can be submitted to the Balancing Mechanism by BSC Parties, although they are not obliged to do so. A bid or offer specifies the price that the BSC Party wishes to be paid (or is willing to pay) to move away from their Final Physical Notification (FPN) and the volume by which they are prepared to move. Bids and offers are financially firm on both BSC Parties and NGC, that is to say BSC Parties are exposed to imbalance prices if they fail to deliver an accepted bid or offer and NGC has to pay BSC Parties compensation if it accepts a bid/offer and then decides it does not require it.

1.10. As well as the Balancing Mechanism, NGC, as SO, has commercial freedom to trade in the short term markets and can use a range of other tools to contract with generators, suppliers and customers to balance the system. It can, for example, enter into balancing services contracts, typically option contracts that allow it to call on a service when it needs it; forward trades (typically non-locational) and Pre-Gate Closure Balancing Transactions (PGBTs). At Gate Closure[10], which occurs one hour before the start of the settlement period, bilateral trading stops and NGC, in its role as SO, takes control of balancing the system.

System balancing

1.11. NGC is responsible for system balancing and delivers against this responsibility mainly through bilateral contracts and the Balancing Mechanism, since system service requirements are often location-specific and hence can not be obtained through the non-locational traded markets. This responsibility is primarily a consequence of the lack of sufficient information and related incentives to enable participants to resolve system balancing issues without a central role being taken by NGC.

1.12. In principle, Ofgem would welcome any developments in this area that would enable market participants to participate more actively in balancing the network, further reducing the need for NGC's central intervention through contracting for system balancing purposes.

Electricity balancing

1.13. Throughout the process of introducing NETA there was extensive consultation[11] regarding the role of NGC versus the role of the market in ensuring electricity balancing. At that time it was recognised that the role of NGC was central in ensuring short-term security of supply (which was defined as the period from day minus one to real time[12]). This was characterised as the "residual balancer" role.

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[10] Gate Closure is the last point at which Parties can notify their contractual position to NETA Central Systems and at which Parties can resubmit their Physical Notifications to NGC. After Gate Closure, NGC uses the Balancing Mechanism to enable them, amongst other things, to keep the system in electricity balance close to, and in, real time by adjusting levels of generation and demand in the light of the Bids and Offers submitted. From NETA go-live until 2 July 2002, Gate Closure was 3½ hours before real time. On 2 May 2002 the Authority accepted BSC Modification Proposal P12 ("Reduction of Gate Closure From 3.5 Hours To 1 Hour") and this modification was implemented on 2 July 2002 from which point Gate Closure was reduced from 3.5 hours to 1 hour.
[11] See, for example 'The new electricity trading arrangements: Volume 1: Consultation Document', Ofgem, July 1999; 'NGC System Operator incentives, Transmission Access and Losses under NETA: Consultation Document', Ofgem, December 1999.
[12] See 'The new electricity trading arrangements: Volume 1: Consultation Document', Ofgem, July 1999 section 12.2.

1.14. Longer term security of supply is delivered by the market and the commercial incentives provided by the trading arrangements. Via exposure to imbalance prices, suppliers face commercial incentives to contract ahead of the Balancing Mechanism to meet the demands of their customers. Generators, also through exposure to imbalance prices, have an incentive to forward contract with customers for their output and to hold reserve to hedge the risks of plant failure. The arrangements give market participants freedom to choose when and how to enter into such contracts. However, imbalances left to the day will tend to be met by generators or demand side participants that have relatively high costs, compared to the prices that could have been obtained by contracting further in advance, including trading in the forward markets.

1.15. Thus, the exposure to imbalance cash-out provides commercial incentives on participants to ensure that the level of generation is sufficient to meet demand. Consequently, NGC is not required to contract in advance to ensure that generation capacity is sufficient to meet peak demand. Under NETA, market mechanisms are intended to play this role and it would not be efficient or economic for NGC to duplicate this by acting, in effect, as the provider/buyer of last resort.

1.16. NGC's role as residual balancer is primarily defined in terms of what other market participants cannot, or cannot at present, efficiently undertake through existing trading and market mechanisms. In its role as residual balancer NGC is responsible for:

- ensuring that demand and supply are balanced on a moment by moment basis;

- managing the physical consequences of any plant failures, including commercial failures[13], that occur on the network for the short period until the market is able to respond to such a failure; and

[13] The term "commercial failure" covers the situation where a generation or supply company goes into receivership or administration. For a short period, contractual obligations may mean that generating capacity is not available to the market or that demand side services are withdrawn.

- managing the physical consequences of any unexpected increases in demand for a short period until the market is able to respond to such an increase.

1.17. In order to mitigate these risks, NGC holds short-term reserve[14]. NGC has the commercial flexibility to procure its reserve requirements through forward tenders/contracts or options and also via the Balancing Mechanism. When assessing the level of reserve requirement and whether to procure its reserve requirements forward or via the Balancing Mechanism, NGC takes account of a number of factors including:

- the likely levels of plant margin;
- the likely levels of generator reliability; and
- the likely levels of demand forecast errors.

1.18. In planning and developing the transmission system and in order to balance the system in an economic, efficient and co-ordinated manner, as required in the terms of its Transmission Licence, NGC should consider the most efficient mechanism by which to deliver its obligations. In delivering against these obligations, NGC should not only consider the economic method and timing of procurement, but also the risk that it will be unable to balance the system in the short-term should the energy required to do so be unavailable close to real time. If NGC anticipates a period of system stress, it is likely that, by factoring in this risk, it would procure more balancing services ahead of time than might be suggested by narrow economic trade-offs.

1.19. NGC's SO incentive scheme provides funding for any costs efficiently incurred by NGC in procuring its reserve requirements and making provisions for eventualities to which the market cannot, or is unaware of its need to, respond.

[14] For more information on NGC's standing reserve procurement see: http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/6060_3904.pdf

NGC's SO incentives

1.20. In order to allow NGC to carry out its role, the commercial arrangements provide NGC with freedom to develop and use a wide range of tools and options to balance the system in the most economic, efficient and coordinated manner. For example, NGC can buy and sell electricity in forward markets and, post Gate Closure, in the Balancing Mechanism. NGC is also free to contract for balancing services[15] from generators, suppliers and large customers. NGC can exercise these contracts for balancing purposes as and when they are required. NGC is required to procure any balancing services competitively and via transparent processes. In order to fulfil this requirement, NGC is obliged under standard condition C16[16] of its transmission licence to have in place two particular documents[17]; the Procurement Guidelines and the Balancing Principles Statement (the purpose of these two documents is further outlined in Appendix 4). NGC's procurement of balancing services is also constrained by a prohibition on purchasing or acquiring electricity other than for the purposes of co-ordinating and directing the flow of electricity onto and over the GB transmission system[18].

1.21. In balancing the transmission system, NGC, in its role as SO, incurs costs for which market participants, and ultimately customers, pay. NGC's SO costs can be divided into internal and external balancing costs. NGC's internal costs include the costs of its control centre, systems and staff. External balancing costs cover the costs of balancing services contracts and electricity purchases and sales for balancing purposes. NGC has consistent incentive schemes covering both internal and external balancing costs. The internal costs incentive targets have been agreed until 31 March 2006 and are being extended for a further

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[15] The term "balancing services" is used to cover both services purchased in the Balancing Mechanism and services contracted outside the Balancing Mechanism.
[16] With effect from 1 September 2004 and following modifications made by the Secretary of State to the electricity transmission licence, what was formerly referred to as special condition AA4 of NGC's transmission licence became standard condition C16 of the electricity transmission licence.
[17] Standard condition C16 obliges NGC to have in place four documents in total; the Procurement Guidelines (PGs), the Balancing Principles Statement (BPS), the Balancing Services Adjustment Data (BSAD) Methodology Statement and the Applicable Balancing Services Volume Data (ABSVD) Methodology Statement. Details of the PGs, the BPS, the BSAD Methodology Statement and the ABSVD Methodology Statement can be found at NGC's website www.nationalgrid.com/uk/indinfo.
[18] This prohibition is contained in standard condition C2 of NGC's transmission licence (it was formerly contained in special condition AA3 of NGC's transmission licence).

year[19]. There have been four external SO incentive schemes under NETA, details of which are provided in Chapter 3 and Appendices 1 and 2. The current external SO incentive scheme commenced on 1 April 2004 and is due to expire on 31 March 2005. Therefore, a new incentive scheme needs to be put in place from 1 April 2005.

1.22. NGC is currently subject to a "shallow" incentive scheme that only covers the costs of operating the transmission system. Ofgem has previously proposed a move to an enhanced, "deeper", incentive scheme that would also include some aspects of the development of the transmission system[20] as is the case for Transco's SO incentives[21]. Ofgem continues to consider that deepening NGC's SO incentive scheme to be appropriate, however, Ofgem is not intending to progress such reforms as part of this consultation process.

1.23. Ofgem intends to develop and implement a new shallow SO incentive scheme which will enhance the existing commercial incentives for NGC to operate and develop the transmission system in an economic, efficient and co-ordinated manner, which is in the interests of customers who ultimately pay for the costs of system operation. Ofgem's Initial Proposals are discussed further in chapter 6.

Related issues

Transmission investment and renewable generation

1.24. In the Government's Energy White Paper[22], one of the key goals for energy policy is to tackle the threat of climate change by reducing greenhouse gas emissions. As part of this policy, the Government is committed to stimulating growth in renewable energy sources and aims for renewables to provide ten per cent of UK electricity supplies by 2010, with the aspiration of this figure rising to 20 percent by 2020.

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[19] 'Transmission price controls and BETTA, Draft proposals', Ofgem, July 2004.
[20] See, for example, 'NGC System Operator incentive scheme from April 2004, Proposals and statutory licence consultation', Ofgem, February 2004.
[21] See 'Transco's National Transmission System system operator incentive 2002-7, Final proposals' Ofgem, December 2001.
[22] The Energy White Paper can be found at: http://www.dti.gov.uk/energy/whitepaper/ourenergyfuture.pdf

1.25. This policy is likely to produce changes in the geographical distribution of generating capacity. The sites for many renewable technologies may be located in remote areas that can be some way from the existing transmission system and/or electricity customers. For increased levels of renewable generation to be delivered to the market, appropriate transmission infrastructure will need to be put in place. This is likely to entail significant extensions to the transmission system, requiring substantial additional investment in the GB transmission networks, including NGC's transmission network.

1.26. An initial consultation in relation to the issues surrounding the appropriate regulatory treatment of any expenditure required to accommodate new renewable generation sources was published in October 2003[23]. The second consultation in May 2004[24] proposed an adjustment mechanism to supplement the existing price controls and to provide appropriate incentives for additional investment in transmission networks.

1.27. Ofgem produced an initial proposals document in relation to theses issues in August 2004[25]. At this stage, Ofgem considers that it is necessary to establish a framework in which the level of efficient investment in the transmission network can be assessed and allowance can be made via appropriate mechanisms. The intention of this approach is to ensure that, once economic justification has been adequately demonstrated, individual investment projects can proceed in a timely manner in order to avoid unnecessary delay.

1.28. Ofgem has assessed the transmission investment proposals put forward by the transmission licensees and has engaged independent consultants to provide additional analysis of these proposals. Ofgem expects to publish its final proposals in December 2004, setting out which transmission investment proposals will be necessary to ensure that forecast levels of new renewable generation can be accommodated.

1.29. The final proposals (due to be published shortly) will provide incentives for transmission licensees to invest efficiently in response to demand from

[23] 'Transmission investment and renewable generation, Consultation document', Ofgem, October 2003.
[24] 'Transmission Investment for Renewable Generation, Second consultation', Ofgem, May 2004.
[25] 'Transmission Investment for Renewable Generation, Initial proposals', Ofgem, August 2004.

generators seeking connections to the transmission and distribution networks ahead of the next price control reviews. The proposals will set out the level of baseline investment which Ofgem considers necessary to accommodate forecast levels of new renewable generation.

1.30. Ofgem will consult on the accompanying licence modifications to the transmission licensees' price controls in early 2005.

Price controls and charging under BETTA

1.31. The current transmission price controls for SHETL and SP Transmission are intended to last until 31 March 2005. Ofgem is proposing to roll forward these price controls for two years to 31 March 2007 to align the price control review dates with those for other transmission licensees in both electricity and gas, enabling all transmission issues to be considered together at the next review. Ofgem published draft proposals in July 2004[26].

1.32. In May 2004[27], Ofgem published an initial proposals document in which it outlined the intended way forward in terms of extending NGC's current price control by one year, to expire on 31 March 2007.

1.33. From BETTA go-live, the price controls of all three transmission licensees will need to be adjusted to provide remuneration according to the licensees' changed roles and responsibilities under BETTA. Therefore, Ofgem's July document contained draft proposals for the price controls to apply to SP Transmission, SHETL and NGC under BETTA, as well as the roll forward price controls that would apply to SP Transmission and SHETL if BETTA go-live were delayed beyond 1 April 2005.

1.34. The price controls to apply under BETTA have been derived by making adjustments to the controls that would apply in the absence of BETTA. Therefore in NGC's case, the price controls to apply under BETTA have been derived by making adjustments to the revenue restrictions that would otherwise apply in

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[26] 'Transmission price controls and BETTA, Draft proposals', Ofgem, July 2004.
[27] 'Extending the National Grid Company's Transmission Asset Price Control for 2006/07, Initial Consultation', Ofgem, May 2004.

2005/6; namely NGC's existing TO price control and its SO internal cost incentives.

1.35. Final proposals for the price controls to apply under BETTA will be published shortly.

1.36. Ahead of the implementation of BETTA in April 2005, NGC has made proposals for its GB transmission charging methodology. The Authority has considered these proposals and has requested that NGC carries out further work[28]. In due course, the Authority will consider revised proposals from NGC for approval.

1.37. Work is also underway to ensure that an efficient mechanism of allocating capacity rights is in place. Should all requests for firm access rights to the transmission system be granted, it is likely that substantial costs could be incurred in the form of actions taken by NGC to relieve constraints. In July 2004, Ofgem issued a consultation[29] relating to the initial allocation of GB transmission system access rights under BETTA. The transitional arrangements are set out in transmission licence condition C18 (in relation to NGC's obligations to users) and in transmission licence condition D15 (in relation to transmission owner obligations to NGC).

Progress to date

Initial Consultation

1.38. Prior to developing the Initial Proposals contained in this document, Ofgem published an Initial Consultation document[30] relating to NGC's SO incentive scheme to apply from 1 April 2005. The Initial Consultation set out the high-level options for the scope, form and duration of the incentive scheme from April 2005 and discussed the treatment of several specific aspects of the scheme. The contents of the Initial Consultation and the responses received to it are summarised in chapter 4. Appendix 3 lists non-confidential respondents to

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[28] 'NGC's proposed GB electricity transmission charging methodologies: the Authority's decisions', Ofgem, December 2004.
[29] 'The initial allocation of GB transmission system access rights under BETTA, A consultation on draft legal text', Ofgem, July 2004.
[30] 'NGC system operator incentive scheme from April 2005, Initial consultation document', Ofgem,

Ofgem's Initial Consultation document. The views of all respondents to the Initial Consultation have been taken into consideration during the development of the proposals presented in this document for NGC's SO incentive scheme from 1 April 2005.

NGT's 2005/06 balancing cost projection

1.39. National Grid Transco (NGT)[31] has provided projections of its Incentivised Balancing Costs (IBC) for 2005/06. As NGC will be responsible for balancing the system on a GB-wide basis from 1 April 2005, NGT's projections cover GB IBC as opposed to just E&W IBC as in previous schemes. Chapter 5 provides information on NGC's projections of IBC for 2005/06 and Appendix 5 contains a paper prepared by NGT which outlines the basis for its forecasting approach and provides details relating to the forecast itself.

Way forward

Timetable

1.40. The publication of this Initial Proposals document represents the second stage in the development of a new SO incentive scheme for NGC to apply from 1 April 2005 following the publication of the Initial Consultation document in September 2004. Following publication of this Initial Proposals document and careful consideration of responses received in relation to it, Ofgem expects to publish a Final Proposals document, including a statutory consultation on proposed modifications to NGC's Transmission Licence, in February 2005.

1.41. If NGC does not consent to the proposed licence modifications, Ofgem has the ability to refer the proposed SO incentive scheme modifications to the Competition Commission for final adjudication.

September 2004.

[31] NGC is the subsidiary of NGT that holds the transmission licence for England and Wales. In this document, references to NGC are only made in respect of licensed activities.

Views invited

1.42. Views are invited in response to the issues raised in this document. Specific issues upon which views are sought are outlined in Chapter 7. Responses should be submitted by 21 January 2005. All responses will normally be published on the Ofgem website and held electronically in the Research and Information Centre unless there are good reasons why they must remain confidential. Respondents to the consultation should try to put any confidential material in appendices to their responses. Ofgem prefers to receive responses in an electronic form so they can be placed easily on the Ofgem website.

1.43. Responses should be submitted by 21 January 2005, either electronically to Wholesale.Markets@ofgem.gov.uk or by post addressed to:

Simon Bradbury

Office of Gas and Electricity Markets

9 Millbank

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Outline of this document

1.45. This document describes Ofgem's Initial Proposals in relation to NGC's SO incentive scheme to apply from 1 April 2005. In detail, this document is structured as follows. Chapter 2 details the Summary Impact Assessment of the possible options associated with NGC's SO incentive scheme from 1 April 2005.

Chapter 3 provides information in relation to NGC's performance under its SO incentive schemes since the implementation of NETA. Chapter 4 provides a summary of the responses to Ofgem's Initial Consultation on NGC's SO incentive scheme from 1 April 2005. Chapter 5 provides information on NGC's projections of IBC for 2005/06. Chapter 6 contains details of Ofgem's Initial Proposals. Chapter 7 provides information on the way forward.

1.46. Appendix 1 outlines the incentive schemes under which NGC has operated since the implementation of NETA. Appendix 2 provides a breakdown of Incentivised Balancing Costs (IBC) components. Appendix 3 lists non-confidential respondents to Ofgem's Initial Consultation document. Appendix 4 summarises the current regulatory framework within which the SO incentives are set. Appendix 5 contains a paper prepared by NGT which outlines cost savings delivered under the 2003/04 SO incentive scheme. Appendix 6 contains a paper prepared by NGT which outlines the basis for its forecasting approach and provides details relating to the forecast itself.

2. Summary impact assessment

Issue

2.1. NGC's existing SO incentive scheme was introduced on 1 April 2004 and is intended to run until 31 March 2005. Therefore, a new incentive scheme needs to be put in place for the period from 1 April 2005 onwards. This coincides with the expected date for BETTA go-live, from which point NGC will perform the role of SO across GB, rather than across just E&W as at present. Therefore, while NGC's SO incentive schemes to date have been developed for its SO role in E&W, NGC's SO incentive scheme intended to apply from 1 April 2005 will be developed for its GB SO role.

2.2. NGC has been subject to incentives to control the costs of balancing the system since 1994. Prior to the introduction of incentive schemes, these costs were passed straight through to customers. In the four years since privatisation, these costs had doubled in real terms to £509 million per annum. Between April 1994 (when the first incentive scheme was introduced) and the introduction of NETA in 2001, NGC reduced the annual costs of system operation by more than £400 million. Since NETA, NGC has consistently managed the costs of system operation such that it has outperformed its incentive scheme target. This has benefited both NGC in terms of the rewards that it has received under the incentive arrangements and customers who ultimately face the costs of system operation and so benefit from a proportion of the cost savings achieved by NGC. The benefits to customers have been enhanced further via successive reductions in the incentive scheme target value (Ofgem has reduced the target for the external SO incentive scheme by around £70 million (from approximately £485 million)). Thus, the schemes have resulted in real benefits to customers, who ultimately pay the costs of system operation.

Objective

2.3. The objective of the SO incentive scheme is to create appropriate commercial incentives for the SO to manage the costs of system operation on behalf of customers. The SO incentives are intended to benefit customers in two ways.

Firstly, they align the interests of NGC with those of customers and, secondly, they transfer some of the risks associated with higher balancing costs from customers to NGC who are better placed to manage them on customers' behalf. In setting a new SO incentive scheme, Ofgem wishes to ensure that these objectives continue to be met and that, as far as is practicable, the incentives on NGC are enhanced.

Policy

2.4. In the Initial Consultation document, Ofgem outlined high-level options for the scope, form and duration of the incentive scheme from April 2005. In summary, Ofgem outlined its preferences as follows:

- the scope of the scheme should be consistent with the existing E&W SO incentive scheme (i.e. to cover all system and electricity balancing costs, recognising the degree of control the SO has over different elements of the costs), whilst acknowledging that the geographic scope of NGC's activities as SO has increased. Ofgem considers that this should ensure that NGC as SO has appropriate commercial incentives to manage on behalf of customers the costs of system operation within its control;

- the form of the scheme should remain in line with the existing E&W SO incentive scheme (i.e. a single scheme for the SO role with a single target value and symmetric cap and floor values and symmetric sharing factors) wherever possible given the potential for uncertainty surrounding system operation costs during the initial period of operation under BETTA. Ofgem considers that maintaining, to as great an extent as possible, the form of the existing scheme should continue to strike an appropriate balance between providing NGC with a reasonable balance of risk and reward whilst protecting customers' interests; and

- for the duration of the scheme to be two years to provide some progress towards the aim of developing longer term incentives.

2.5. Following consideration of the views of respondents to the Initial Consultation on these issues and the treatment of several specific aspects of the scheme, Ofgem has developed several options for NGC's SO incentive scheme from 1

April 2005 to be considered as its Initial Proposals. These options and the rationale behind them are discussed further in chapter 6.

3. NGC's external SO incentive schemes since the implementation of NETA

Introduction

3.1. This chapter provides a background to the Initial Proposals set out in this document by outlining NGC's performance under the first four external cost incentive schemes under NETA. Details of the structure of these incentive schemes are provided in Appendix 1. Further details of NGC's performance under the schemes are provided in Appendix 2. In addition, Appendix 5 contains a paper prepared by NGT outlining cost savings under the 2003/04 SO incentive scheme.

Background

3.2. Under the external SO incentive schemes that have been in place since NETA was introduced, NGC is allowed to recover the actual costs of electricity balancing and system balancing, adjusted by incentive payments or receipts relating to these costs. The value of any incentive payments or receipts depends upon NGC's performance in relation to a cost target set in advance.

3.3. If NGC's costs are below the target, it keeps a proportion (set by the upside sharing factor) of the reduction in costs as an incentive payment. Conversely, if its costs are above the target, NGC is charged a proportion (set by the downside sharing factor) of the costs in excess of the target. NGC's overall gains or losses on its balancing costs are limited by applying a cap on payments and a floor on losses. This type of scheme is called a sliding scale or profit sharing scheme. In setting incentive scheme targets, sharing factors, caps and floors, Ofgem aims to provide NGC with an appropriate balance of risk and reward in the interests of customers.

NGC's performance under the SO incentive schemes since the implementation of NETA

Annual IBC

3.4. NGC has performed well against the targets that have been set by Ofgem for each of its incentive schemes under NETA to date. As a consequence, NGC has received incentive payments to reward this performance within the terms of these incentive schemes. However, the incentive schemes that NGC has been subject to have seen consistent reduction in the costs that NGC recovers from its customers. The incentive schemes, therefore, provide substantial cost savings for market participants and customers alike. Table 3.1 provides details of the target values of IBC, the actual end of year IBC, the cost saving between actual and target IBC, and the incentive payment that NGC has received or paid.

Table 3.1 – NGC's performance under each incentive scheme (money of the day)

Parameter	2001/02 scheme[32]	2002/03 scheme	2003/04 scheme	2004/05 scheme	
	Actual outturn			Straight line extrapolation[33]	NGT's forecast outturn
Target IBC	£484.6 million to £514.4 million	£460.0 million	£416.0 million	£415.0 million	
Outturn IBC	£365.6 million	£379.0 million	£351.5 million	£373.0 million	£394.9 million
Cost saving (overrun) vs target[34]	£119.0 million	£81.0 million	£64.5 million	£41.7 million	£20.1 million
NGC's incentive reward (payment)	£46.3 million	£48.6 million	£32.2 million	£16.7 million	£8.0 million

3.5. In the initial incentive period under NETA, IBC totalled approximately £366 million. As a result, NGC received the maximum (cap) payment of £46.3

[32] The figures presented in relation to the initial incentive scheme represent the finalised parameters for the scheme following adjustments to reflect that the scheme was 370 days in duration, not 365 days, and inflation indexation at 1.5 per cent.
[33] This straight line extrapolation is based on data from 1 April 2004 to 31 October 2004.

million under its SO external cost incentive. This reflected the fact that, over the first year of NETA, NGC substantially reduced the level of SO costs and therefore its performance was rewarded under its incentive scheme. The growing experience of operating under NETA has allowed Ofgem to set lower target values in successive years. As a result of the substantial reduction in SO balancing costs, Ofgem has been able to set the target for the current SO external cost incentive around £70 million lower than the original incentive scheme target.

3.6. In the second incentive period, IBC totalled £384.3 million by year end but was reduced by £5.34 million to stand at £379 million as a result of an approved Income Adjusting Event (IAE)[35]. NGC's incentive payment was £48.6 million for the second incentive period (increased by £3.2 million from £45.4 million as a result of the approved IAE)[36].

3.7. In the third incentive scheme period, IBC totalled almost £357.1 million by year end compared to a target of £416 million, but was reduced by £5.54 million to stand at £351.5 million as a result of an approved IAE. NGC's incentive payment was £32.2 million for the third incentive scheme period (increased by £2.77 million from £29.5 million as a result of the approved IAE)[37].

3.8. Under the current incentive scheme period, a straight line extrapolation of the available IBC data until 31 October 2004[38] (cumulative IBC was £218.7 million

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[34] The sharing factors built into the SO incentive arrangements allow for a proportion of these savings (overruns) to be passed onto (borne by) customers. As savings have been made to date, the proportion of these cost savings to be passed onto customers was set at 60 per cent for 2001/02, 40 per cent for 2002/03, 50 per cent for 2003/04 and 60 per cent for 2004/05.

[35] The IAE provisions are intended to provide protection for both NGC and customers in the event that an incident results in costs or savings which were not envisaged at the time that the SO incentive parameters were defined. As the event could not be envisaged, no allowance for costs or savings linked to such incidents is made within the SO incentive scheme target. NGC, or any other BSC Party, can give notice to Ofgem that they consider an IAE to have occurred where they consider that the costs and/or expenses caused or saved by the IAE have affected NGC's IBC by more than £2 million. The £2 million threshold does not apply if the IAE is a security period as defined in special condition AA5D of NGC's transmission licence.

[36] See 'Income adjusting event under NGC's 2002/03 system operator incentive scheme: A consultation document', Ofgem, May 2003 and 'Income adjusting event under NGC's 2002/03 system operator incentive scheme: A decision document', Ofgem, June 2003. These documents can be found on Ofgem's website at www.ofgem.gov.uk

[37] See 'Income adjusting event under NGC's 2003/04 system operator incentive scheme: A consultation document', Ofgem, May 2004 and 'Income adjusting event under NGC's 2002/03 system operator incentive scheme: A decision document', Ofgem, July 2004. These documents can be found on Ofgem's website at www.ofgem.gov.uk

[38] Please note that this extrapolation is only based on seven months of data.

for this period) yields a cost of £373.0 million over the entire incentive period. This would equate to NGC receiving around £16.8 million, significantly below the maximum allowable payment (cap) of £40 million. NGC has forecast that outturn IBC for the current incentive period will total £394.9 million. This forecast outturn would equate to NGC receiving around £8 million.

3.9. NGC has made good progress in reducing the overall level of SO costs since NETA go-live and has accordingly received incentive rewards during these periods. The cost savings achieved are beneficial to customers, who ultimately bear the costs of system operation. The benefits to customers have been enhanced further via successive reductions in the incentive scheme target value.

Within-year IBC

3.10. NGC's performance against its incentive scheme depends in part upon the market conditions that prevail during the relevant incentive scheme period. For example, one would expect IBC to be higher in a particularly cold year than a mild year as a consequence of the effect that weather has on the demand for electricity. Equally a particularly hot year could put upward pressure on IBC as air conditioning is a large component of electricity demand. In addition to seasonal conditions that affect the demand for electricity, IBC is affected by changes in the supply of electricity. Where the availability of generation plant is scarce, one would expect IBC to be pushed upward. Via these supply and demand fundamentals, the value of IBC is heavily influenced by the time of year and generator behaviour. Over time, however, NGC has gained greater experience and is better equipped to deal with these fundamentals and make cost savings. To illustrate, total IBC and daily average IBC both on a monthly basis under each incentive scheme are shown in Figures 3.1 and 3.2.

Figure 3.1 – Monthly IBC under each incentive scheme (money of the day)[39]

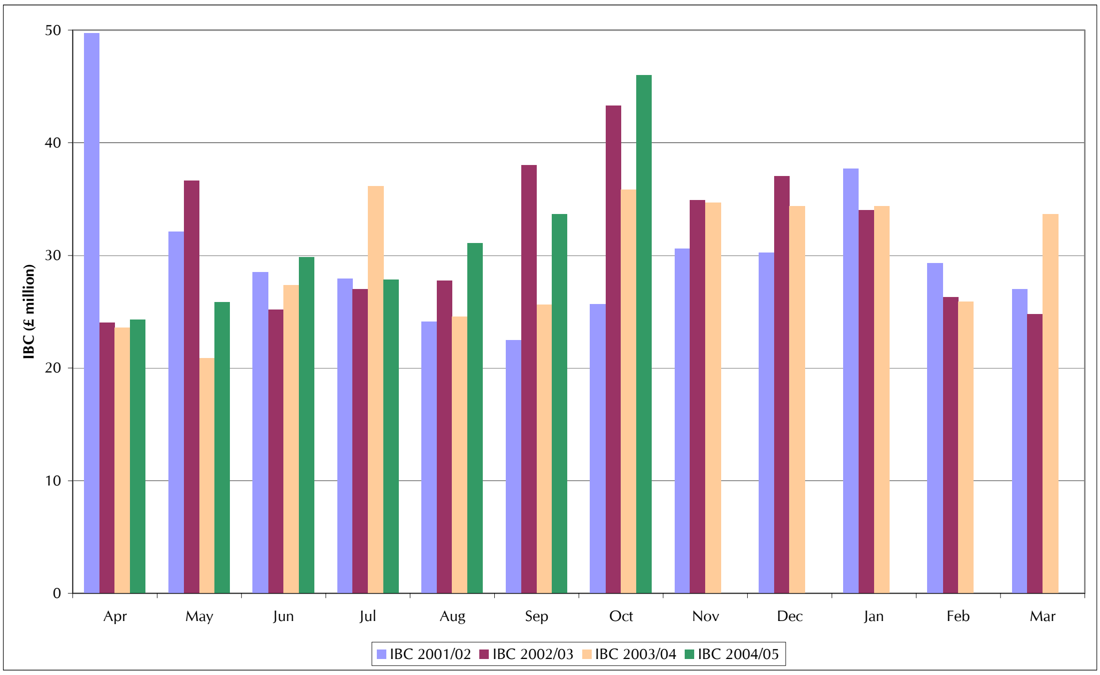
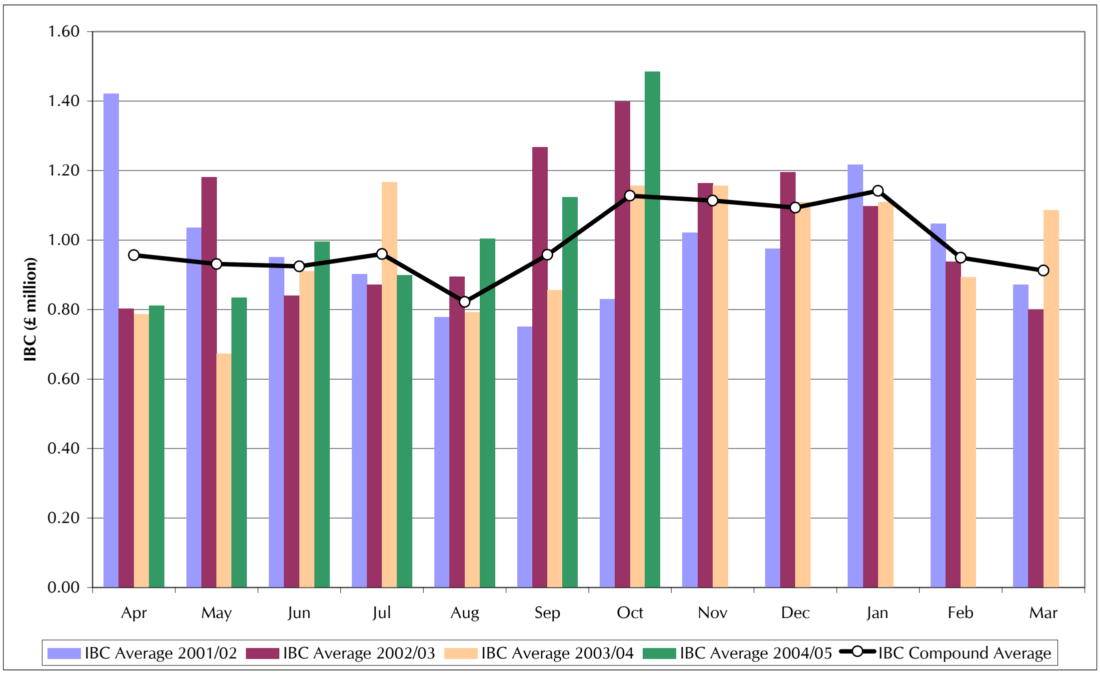


Figure 3.2 – Daily average IBC by month under each incentive scheme (money of the day)[40]



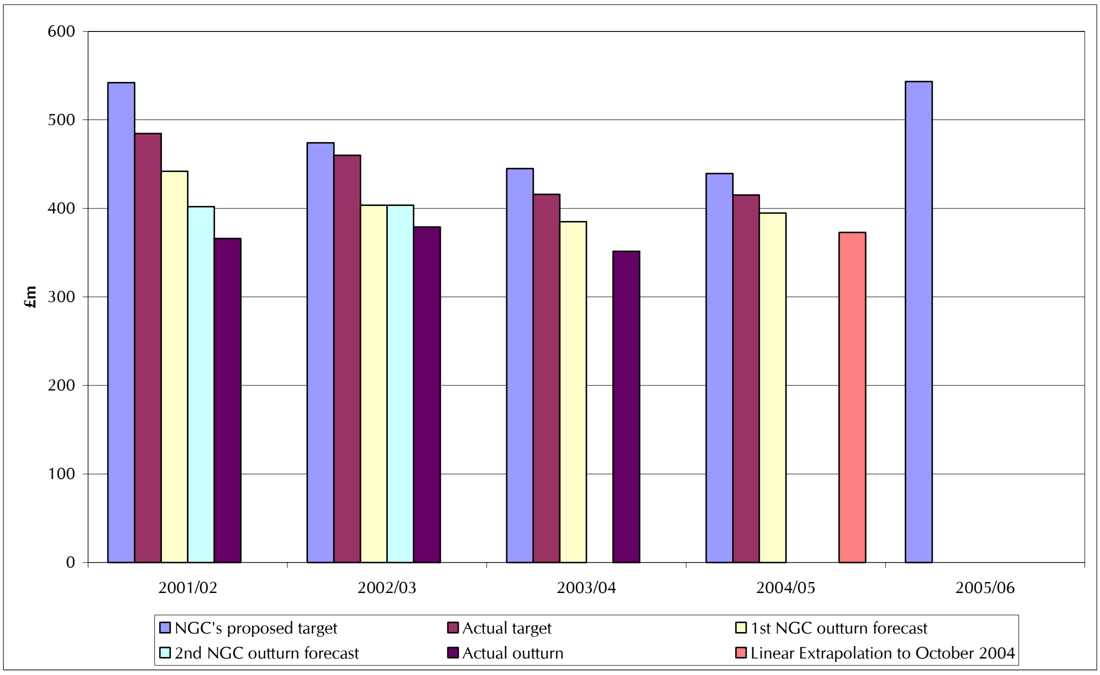
[39] Data for March 2001 is added to data for April 2001 in this graph.
[40] Data for March 2001 is added to data for April 2001 in this graph. The IBC compound average is based on producing averages for 365 days (e.g. for 1 April, average 1 April 2001, 1 April 2002, 1 April 2003 and 1 April 2004), then averaging this by month.

Historic IBC forecasts versus outturns

3.11. Under each incentive scheme since NETA go-live, NGC has used essentially the same methodology to produce forecasts of IBC for the forthcoming incentive scheme period. The methodology is based on using historic data to forecast future costs.

3.12. An examination of the three incentive scheme periods for which complete end of year data is available shows that NGC's proposed target for IBC has been between 25 per cent and 48 per cent higher than the actual outturn figure for IBC. In addition, NGC's first forecast of IBC once the incentive scheme has commenced has been between seven per cent and 21 per cent higher than the actual outturn figure for IBC. For illustrative purposes, Figure 3.3 provides a representation of NGC's IBC forecasts[41], Ofgem's proposed IBC target, and end of incentive scheme period IBC outturn. In addition, the chart includes a straight line extrapolation of outturn IBC for incentive scheme 2004/05, based on data to end October 2004, and NGC's forecast for IBC under BETTA.

Figure 3.3 – Comparison of forecast and outturn IBC under each incentive scheme (money of the day)[42]



[41] Where these forecasts have been provided.
[42] There is no second NGC forecast for 2003/04.

Conclusions

3.13. NGC has made good progress in reducing the overall level of SO costs since NETA go-live. This is likely, at least in part, to reflect NGC's improved understanding of operating the system under NETA and its response to the incentives. The cost savings achieved are beneficial to customers, who ultimately bear the costs of system operation. The benefits to customers have been enhanced further via successive reductions in the incentive scheme target value.

3.14. In the first year under NETA, IBC totalled approximately £366 million and NGC received the maximum incentive payment of £46.3 million. The second incentive scheme set a lower target and higher upside sharing factor, with IBC totalling £379 million (after the approved IAE) compared to a target of £460 million. Consequently, NGC received a payment of £48.6 million. The third incentive scheme adopted symmetric sharing factors, thereby providing NGC with the same proportion of risk and reward. As a result, IBC for 2003/04 fell to £351.5 million (also following an approved IAE), relative to a target of £416 million. Under the current scheme, a linear extrapolation of the costs to end October 2004 suggests that IBC may be over £35 million lower than the target, despite recent increases in IBC, while NGC's forecast of outturn IBC suggests a value around £20 million below the target.

3.15. Under each incentive scheme to date, NGC has been able to manage the operation of its transmission system such that its IBC has, by the end of the incentive scheme period, been substantially lower than its proposed target in advance of the relevant incentive scheme and its initial forecast figure following the commencement of the relevant incentive scheme.

4. Responses to Ofgem's Initial Consultation

Introduction

4.1. This chapter summarises Ofgem's initial thoughts as presented in the September 2004 Initial Consultation and outlines respondents' views, including those of NGT, in relation to the issues raised within the document. A list of the non-confidential respondents to the Initial Consultation is provided in Appendix 3[43].

Ofgem's initial thoughts

Scope of the GB SO incentive scheme to apply from 1 April 2005

4.2. NGC's SO incentive schemes since NETA go-live have covered all system and electricity balancing costs, whilst recognising the degree of control the SO has over different elements of the costs. While bearing in mind that the geographical scope of the SO incentive schemes from April 2005 onwards will be greater given that the SO role will be GB-wide, Ofgem considered that the existing scope of the E&W SO incentive schemes will continue to provide appropriate commercial incentives for NGC to manage the costs of system operation on behalf of customers. Therefore, while the geographical scope of the SO role will change, Ofgem did not consider that the scope of the incentive scheme required amendment and considered that the existing scope provides an appropriate basis upon which to develop GB SO incentive arrangements.

Form of the GB SO incentive scheme to apply from 1 April 2005

4.3. NGC's SO incentive schemes since NETA go-live have been sliding scale incentives with appropriate target, cap, floor, and sharing factor values. Ofgem outlined that it continued to consider that a sliding scale incentive scheme with

[43] Copies of the non-confidential responses have been placed in Ofgem's library and are available on the Ofgem website at http://www.ofgem.gov.uk/ofgem/search-

a single target value and symmetry between the cap and floor values and between the sharing factors to be appropriate.

4.4. However, Ofgem acknowledged that there may be some uncertainty associated with the level of balancing costs under BETTA and highlighted the following as potential sources:

- **Transmission investment for renewable investment:** Substantial volumes of new renewable generation plant are now under construction or in planning and it has become clear that investment will be required to strengthen and extend the transmission system, particularly in Scotland and potentially in Northern England. If the transmission investment that is now required is not progressed until the start of the next price control period (April 2007), either the construction of new renewable generation is likely to be delayed or generation may need to be constrained, potentially resulting in substantial constraint payments. Should the current volume of plant with firm capacity rights be afforded access to the GB transmission system, then it is likely that there would be substantial pinch points, caused by insufficient capacity in the transmission network. Where this occurs, there would be scope for incurring substantial day to day operational constraint management costs.

- **Access allocation:** In July 2004, Ofgem issued a consultation[44] relating to the initial allocation of GB transmission system access rights under BETTA. The transitional arrangements proposed to grant access rights to all parties who have a relevant agreement with a transmission licensee as at 1 September 2004 and all parties who have applied for a connection offer from a transmission licensee prior to 1 January 2005[45]. The form of the GB SO incentive scheme may, therefore, have to accommodate any

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[44] 'The initial allocation of GB transmission system access rights under BETTA, A consultation on draft legal text', Ofgem, July 2004.

[45] The offer is not contingent on completion of network reinforcement works on circuits relating directly to the Scotland-England interconnector (or works directly consequential to such network reinforcement). Also, parties connecting in Scotland shall not receive an offer contingent on the completion of works in E&W, and parties connecting in E&W shall not receive an offer contingent on the completion of works in Scotland.

developments in the way in which GB transmission system access rights and any potential constraint issues are managed.

- **Scottish balancing costs:** As part of the process for establishing the forecast Balancing Services Incentive Scheme (BSIS) costs, NGC produces a breakdown of historic costs and then considers how these costs might change in the future. While historic information is available in an E&W context for this purpose, utilising an extrapolation of this kind to derive a forecast of GB wide BSIS costs is hampered by the potential information issues in relation to the likely contribution of Scottish balancing costs to overall BSIS costs. This, therefore, creates an element of uncertainty when forecasting BSIS.

4.5. Ofgem outlined that it considered that the uncertainty surrounding the level of balancing costs in advance of BETTA go-live is significantly less than was the case ahead of NETA go-live and Ofgem did not, therefore, envisage making substantive amendments to the general form of the SO incentive arrangements to accommodate it. However, to the extent that uncertainty does exist, Ofgem considered it to be appropriate for this to be reflected in the form of the SO incentive arrangements. Ofgem outlined that one or more of the following options could be considered in order to accommodate any uncertainty:

- **separate SO schemes for Scotland and E&W:** While this would allow any uncertainty associated with the extension of NGC's SO role to include Scotland to be handled under a separate incentive scheme, Ofgem considers that this option would risk introducing inconsistent incentives for the SO activity as a whole and could create perverse incentives between the different incentive arrangements. Ofgem considers that it is important for the GB SO role to have a single incentive scheme to ensure consistent incentives apply across GB.

- **deadband target range:** As at NETA go-live, a deadband target would offer a mechanism with which to mitigate the risk associated with any uncertainty linked to the GB SO activities post-BETTA go-live. Ofgem's preference would be to avoid re-introducing a deadband target range because, as previously stated, this creates a range of costs within which NGC has reduced incentives to manage costs on behalf of customers.

- **asymmetric cap, floor and sharing factors:** Reducing the downside exposure of the incentive scheme relative to the upside reward offers another option to accommodate within the incentive scheme any perceived uncertainty in relation to GB SO costs. Ofgem's preference would again be to avoid this approach wherever possible in the absence of evidence of asymmetric cost distributions.

Duration of the GB SO incentive scheme to apply from 1 April 2005

4.6. Ofgem has previously suggested that, over the longer-term, the duration of NGC's SO incentive schemes should be lengthened and made consistent with the duration of NGC's TO price control. Whilst acknowledging that the next SO incentive scheme will be the first under BETTA, Ofgem is of the view that it is appropriate to consider implementing an external SO incentive scheme of longer than one year in duration from 1 April 2005. Ofgem consulted on the options of a one year scheme and a two year scheme in the Initial Consultation document.

Timing of BETTA go-live

4.7. While confident that BETTA go-live will be achieved on time on 1 April 2005, Ofgem sought to ensure that the SO incentive arrangements to apply from 1 April 2005 would be robust to any delay in the BETTA timetable. Therefore, Ofgem outlined possible contingency arrangements which might be required to ensure that appropriate SO incentive arrangements would be in place in the event that BETTA go-live occurs after 1 April 2005. Ofgem outlined two options which it considered would lead to minimum disruption to the operation of the SO incentive arrangements under which NGC operates.

4.8. Option 1 was as follows:

- for each relevant year within the intended incentive period from 1 April 2005 (the intended BETTA go-live date) onwards, define annual GB SO incentive scheme parameters from BETTA go-live;

- in the event that BETTA go-live is delayed, roll-over the existing E&W SO incentive scheme for the period between 1 April 2005 until BETTA go-live, automatically cutting over to the pre-agreed GB SO incentive scheme as of BETTA go-live;

- profile the annual target, cap and floor parameters in the rolled over E&W SO incentive scheme to derive an appropriate value for the period over which it applies ahead of actual BETTA go-live;

- profile the annual target, cap and floor parameters in the GB SO incentive scheme to derive an appropriate value for the period over which it applies after actual BETTA go-live;

- one possible option for a profiling factor is that used in the initial incentive scheme under NETA in order to accommodate a scheme which was more or less than one year in duration. Similar profiles could be developed to apply within the context of this approach.

4.9. Option 2 was as follows:

- for each relevant year within the intended incentive period, define the SO incentive scheme parameters (determined following consultation) to apply for the E&W SO incentive scheme;

- for each relevant year within the intended incentive period from 1 April 2005 (the intended BETTA go-live date) onwards, define additional "adjuster" parameters to amend the E&W SO incentive scheme parameters from BETTA go-live;

- the adjuster parameters would be assigned annual values (determined following consultation) to reflect the changes to the E&W SO incentive scheme parameters considered appropriate in light of the switch to GB-wide application; and

- the adjuster parameters would have a zero value until BETTA go-live occurs. If BETTA go-live were to occur after the start of a relevant year (i.e. not on 1 April) within the intended incentive period duration, the annual adjuster parameters would be profiled accordingly. The profiling methodology outlined above could also be considered within this context.

4.10. Ofgem considered that the approaches outlined above offered a practical way to deal with the possibility that BETTA go-live occurs after 1 April 2005.

Other issues

Net Imbalance Adjustment[46]

4.11. Ofgem outlined that following APX's acquisition of UKPX, the calculation of the Single Price Net Imbalance Volume Reference Price (SPNIRP) component of the Net Imbalance Adjustment (NIA) is now being derived on the basis of the price of the single power exchange which implies that the default arrangements associated with the SPNIRP calculation may be used more frequently. As these mechanisms were intended to provide a default position in cases where there is no power exchange information or information from just one power exchange rather than on a more permanent basis, Ofgem considered that it could be appropriate to review the SPNIRP calculation methodology. Ofgem considered that any such review should also examine the values attached to the price adjusters. These values were set as part of the 2002/03 SO incentive scheme and have not been revised since.

Transmission Losses Adjustment[47]

4.12. Ofgem considered that Scottish and E&W transmission losses should be included within the same incentive package to provide consistent incentives in respect of transmission losses across the whole of GB. For the same purpose, Ofgem outlined that the Transmission Losses Reference Price (TLRP) component of the Transmission Losses Adjustment (TLA) should be applied consistently across GB.

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[46] The Net Imbalance Adjustment (NIA) component of NGC's SO incentive scheme is designed to adjust NGC's costs to reflect the fact that it has little control over the extent to which participants choose not to balance their positions. NIA is derived by multiplying the system imbalance volume by the Net Imbalance Volume Reference Price (NIRP) for each Settlement Period.

[47] The Transmission Losses Adjustment (TLA) element of NGC's SO incentive scheme is designed to provide an incentive for NGC to manage the volume of transmission losses. TLA is derived by multiplying the volume of transmission losses by the Transmission Losses Reference Price (TLRP).

BSC Modification Proposals and CUSC Amendment Proposals

4.13. As is the case under the current SO incentive scheme, Ofgem considered that for the forthcoming incentive scheme the IAE provisions should not be applied for a specified list of Modification Proposals to the BSC and Amendment Proposals to the CUSC.

4.14. Ofgem also highlighted that the treatment of CUSC Amendment Proposal CAP047[48] and CUSC Amendment Proposal CAP048[49] within the incentive arrangements was yet to be finalised.

TO incentives

4.15. Ofgem outlined that it would expect the costs of outage shuffling to be offset by savings in NGC's SO external cost scheme and that it intended to take them into account in setting the targets and incentives under the scheme.

Respondents' views

4.16. Ofgem received ten responses, including NGT's, to its Initial Consultation. All responses were not confidential and have been published on Ofgem's website[50]. A summary of respondents' views is provided below, followed by a summary of NGT's views.

Scope of the GB SO incentive scheme to apply from 1 April 2005

4.17. The majority of respondents who directly commented on the scope of the incentive scheme were of the view that the existing scope of the SO incentive scheme should be retained. Of these respondents, a number suggested that NGC will have essentially the same role as at present, and the scope should be commensurate to this role. However, several respondents suggested that the

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[48] CUSC Amendment Proposal CAP047: "Introduction of a competitive process for the provision of Mandatory Frequency Response".
[49] CUSC Amendment Proposal CAP048: "Firm Access and Temporary Physical Disconnection".
[50] Copies of the response are available on the Ofgem website and have been placed at the following location: http://www.ofgem.gov.uk/ofgem/search-result.jsp?plusorminus=plus&articleid=8441&keywords=so%20incentive%20scheme%20&page=1 and

scope should be limited to the costs that NGC directly controls. One such respondent questioned whether the treatment of transmission losses is consistent with this requirement.

4.18. Several respondents remarked that going forward it would be appropriate to review the scope of the incentives with a view to removing those balancing services where competitive provision ensures that NGC procures the services economically and efficiently. One respondent considered that NGC should look to develop a mechanism for procuring reserve, to mimic the half hourly electricity market, in order to remove the requirement for an incentive scheme. Another respondent considered that NGC should not need an incentive scheme to minimise costs as it is required by its licence to operate the system in an efficient and economic manner. A further respondent expressed the view that NGC should only have incentives in relation to those areas where competition was not ensuring economic procurement (e.g. constraint management).

Form of the GB SO incentive scheme to apply from 1 April 2005

4.19. For the most part, respondents considered that the current form of the incentive scheme should be retained, with a single target, symmetric cap and floor and symmetric sharing factors. However, (with the exception of NGT) all respondents that directly commented on the issue considered that NGC was not being sufficiently challenged under its external SO incentive scheme and called for a tighter target. Three respondents called for lower cap and floor values and lower sharing factors, while one respondent called for a reduction in the upside sharing factor and the cap to limit NGC's potential reward. Several respondents also considered that NGC's forecasts were biased and considered that more information on NGC's IBC forecasts should be made available to reduce the bias.

4.20. Although it was recognised by a number of respondents that there would be uncertain elements involved in extending the E&W arrangements to GB, all respondents that directly commented on the issue were of the view that a single

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have been placed in Ofgem's library.

GB wide scheme should be employed. Several respondents agreed with Ofgem that having a separate incentive scheme for Scotland would create arbitrage opportunities and therefore perverse incentives for NGC to take actions that were not optimal, on the basis that it could benefit from its incentive scheme.

4.21. In order to accommodate any uncertainty, one respondent considered that using asymmetric values (with lower downside exposure) should not be discounted, as it considered that there are some asymmetric risks that the SO needs to account for. Another respondent suggested a mechanism with two tiers of sharing factors. Low sharing factors could be used over the uncertain cost range representing low levels of risk/reward for costs that can not be easily predicted, whilst retaining some incentive. Higher sharing factors could be used for the cost ranges where there is a higher degree of certainty as a result of historical or known factors. An alternative form suggested by this respondent was to identify those areas of uncertain costs that NGC has little control over, and then apply an IAE at the end of the year to reflect the outturn cost factors.

4.22. One respondent considered that the inclusion of uncertain Scottish balancing costs should not result in a loosening of the incentives on NGC. The majority of respondents considered that it was not appropriate to make a substantial amendment to the GB SO incentive scheme to reflect the costs of accommodating Scotland. A number of respondents considered that the increased competition from Scottish generation would result in a less than proportionate increase in balancing costs.

4.23. The majority of respondents considered that although there was uncertainty associated with Scottish balancing costs, this should not serve to reduce the incentive placed on NGC to reduce costs. One respondent considered that there was no reason why accommodating Scotland should soften the downward pressure on costs, as the previously administered price arrangements in Scotland were based on E&W wholesale prices. However, one respondent was concerned that continuing downward pressure on balancing costs could have an adverse effect on the security of supply.

4.24. One respondent was concerned that there was an area of uncertainty surrounding the connection to the Shetland Isles. Under BETTA and the Distribution Price Control Review (DPCR), Ofgem determined that Scottish

Hydro Electric Power Distribution (SHEPD) is responsible for balancing on the Shetland Isles as there is no connection to NGC's system. However, it was considered that NGC will likely charge SHEPD for Transmission Network Use of System (TNUoS) charges and Balancing Services Use of System (BSUoS) charges for the affected area. A further respondent considered that the costs associated with accommodating renewable generation in Scotland and for constraint relief made a case for there being a lower downside sharing factor. Another respondent considered that constraints would be a particularly difficult area to forecast as they will not have existed in the same format under NETA.

Duration of the GB SO incentive scheme to apply from 1 April 2005

4.25. Most respondents considered that due to the lack of operational experience under BETTA, it would be desirable to develop a one year scheme from April 2005. One such respondent considered that having a one year scheme will allow for resetting the parameters after one year and will involve less risk. However, most of these respondents considered that a longer term incentive scheme was desirable in theory.

4.26. Only one respondent considered that, as there would only be six months of operational data under BETTA available at the time when the incentive scheme process starts for 2006/07, it may be more beneficial to have a two year scheme and review the second year's parameters after the first year.

Timing of BETTA go-live

4.27. There was no clear consensus as to which mechanism should be adopted were there a delay to BETTA go-live. One respondent expressed that it was relaxed over the mechanism used to accommodate a short term delay in BETTA go-live, as it was confident there would not be such a delay.

4.28. Of those respondents that expressed a strong preference, one respondent considered option 1[51] would be the more efficient as creating a new SO

[51] Option 1 consists of defining GB SO incentive scheme parameters to apply from BETTA go-live. Should BETTA go-live be delayed, the existing E&W scheme would be rolled over until BETTA go-live, but would

incentive scheme for E&W would not be required. One respondent proposed a variant of Option 1, suggesting that a new E&W scheme and a Scotland scheme be devised. The E&W scheme would be used should BETTA go-live be delayed, and be profiled accordingly. When BETTA goes live, the GB scheme would be activated, and be profiled for the remainder of the year. Alternatively, one respondent considered that Option 2[52] was the most appropriate. This respondent considered that if a new scheme was set for England and Wales (E&W) it would be based on lower costs and lower BSUoS than in previous years. By adjusting this figure with the parameters for GB, the lower costs will be applied to GB. Another respondent in favour of Option 2 considered that it would serve to improve transparency of the forecast balancing costs.

Other issues

Net Imbalance Adjustment

4.29. Of those respondents that directly commented, the majority considered that it may be worth reviewing the way in which NIRP is calculated, following the merger of UKPX and APX. One respondent considered that it was not necessary to review NIRP following the merger, and considered that the existing methodology was sufficiently robust for another year.

4.30. Several respondents additionally considered that it might be useful to review the price adjusters. One respondent considered that there may be merit in removing the price adjusters such that NIRP = SPNIRP. This respondent was of the view that there was no real reason why NIRP should not be based on just one power exchange's data.

Transmission Losses Adjustment

4.31. All market participants who commented suggested that it would be appropriate to have a single GB wide scheme for transmission losses. One respondent considered that as the Secretary of State believes that losses should be charged

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be profiled accordingly. At BETTA go-live the scheme would cut over to the pre-agreed parameters.

[52] Option 2 involved defining SO incentive scheme parameters for E&W and defining adjuster parameters to amend the E&W scheme from BETTA go-live. The adjuster parameters would be assigned annual values and would be set at zero until BETTA go-live. These annual adjusters are then profiled according to the

uniformly across GB, it is appropriate to have a single TLA for GB. One respondent considered a consistent scheme across GB was appropriate but was unsure of what NGC actually does to manage losses. This respondent considered that transmission losses should not be included in the external SO incentive scheme.

4.32. A number of respondents considered that the methodology for charging transmission losses should be reviewed ahead of BETTA. One such respondent was of the view that TLA should be revised so that there is a specific value for every half hour using the existing methodology for calculating NIRP.

4.33. One respondent expressed a view that NGC's actions only have a marginal effect on transmission losses. Dispatch patterns and therefore losses are determined by market participants' FPNs. This respondent added that TLRP may need reviewing ahead of BETTA, and perhaps seasonal prices should be used for peak and off peak to reflect the prevailing baseload forward price.

BSC Modification Proposals and CUSC Amendment Proposals

4.34. The majority of respondents considered that specified Modification Proposals and Amendment Proposals should be excluded from being eligible for IAE treatment. Several respondents considered that the current IAE provisions were asymmetric and should be improved.

4.35. One respondent considered that it would be undesirable to make allowance for CAP047 in the SO incentive scheme. This respondent considered that instead a retrospective adjustment should be made on the basis of actual incurred costs.

4.36. One respondent considered that, in the absence of the consultation on CAP048, it was unclear whether CAP048 should be included in the SO incentive scheme.

TO incentives

4.37. There was a wide range of views as to how the costs of outage shuffling should be dealt with, and how this related to the allowance made in the TO incentive. One respondent considered that there should not be an adjustment to the

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length of the delay to BETTA.

external incentive scheme to reflect the costs of outage shuffling. Instead these costs should be absorbed by NGC. Another respondent considered that as NGC currently includes the costs of outage shuffling in its E&W scheme; it would need strong justification to extend this to GB. One respondent considered that adjustments should be made to the incentive scheme to reflect the allowance within NGC's BETTA TO control. A further respondent considered that compensation for outage shuffling should be included in NGC's internal incentive only.

4.38. One respondent was of the view that there is inconsistency between the treatment of outages under the TO scheme allowance, and the incentives on constraint management. This respondent considered that it would be in a better position to assess the issue once there is more clarity on the costs of outage shuffling.

NGT's view

Scope of the GB SO incentive scheme to apply from 1 April 2005

4.39. NGT considered that the incentive scheme should cover all balancing costs within the scope of the GB SO. NGT recognised that while the geographical scope of the scheme will change as a result of BETTA implementation, NGT's SO role will essentially remain the same. As a consequence, NGT considered that the costs covered by the current incentive scheme to be broadly appropriate, subject to the adoption of an appropriate form of scheme

Form of the GB SO incentive scheme to apply from 1 April 2005

4.40. NGT considered that a similar scheme to the current arrangements, with a sliding scale and single target continues to be the preferred option. However, NGT considered that market changes and uncertainty associated with the implementation of BETTA might cause significant asymmetry of risk. NGT considered that although the risk associated with BETTA will be less than was the case for NETA, several areas are still significantly uncertain. In particular, NGT agreed with Ofgem's assertion that there may be significant constraint costs as a consequence of allocating firm access rights to all applicants that applied for a connection to the GB system prior to 1 January 2005.

4.41. NGT considered that due to the asymmetry of risk, it may be necessary to change the form of the incentive scheme for two main reasons. First, there is a lack of equivalent market data for Scotland and, secondly, there is considerable uncertainty as to how the market will operate in Scotland following the implementation of BETTA.

4.42. NGT considered that it would be difficult to agree a separate cap, floor and sharing factors for Scotland as NGT would need to allocate the costs of balancing actions to one of the two schemes or allocate different portions to each scheme, despite the potential for a single action to affect both schemes. For example, a balancing action to reduce the output of a generator in E&W may have the effect of managing volumes in Scotland, but there is no unique way of assigning these costs to separate geographical areas.

4.43. NGT considered that the option of a deadband target should not be ruled out. NGT suggested that there are a number of areas in which NGT's degree of control over costs is uncertain. A deadband may be an appropriate option to mitigate NGT's risk that this is the case.

4.44. NGT noted that there are some cost areas in which NGT is exposed to asymmetric risk and that an asymmetric cap, floor and sharing factors may be appropriate in the initial period following BETTA go-live, as was the case with NETA go-live. NGT considered that prior to 2003/04, the E&W SO incentive scheme allowed for asymmetry and noted that it was only following two years of operational experience that symmetry was introduced.

Duration of GB SO incentive scheme

4.45. NGT stated that, in principle, it continues to support the development of longer-term incentive arrangements. However, NGT considered that the uncertainty associated with a two-year scheme is too great at present. NGT stated three main reasons why this is the case. First, there is uncertainty as to the extent to which transmission network reinforcements will be carried out during 2006/07 to accommodate renewable generation. Secondly, there is still uncertainty as to the volume of renewable generation due to come on-stream during this period. Finally, there is further uncertainty regarding the development and operation of the new market, and impact on market participants' behaviour.

Timing of BETTA go-live

4.46. NGT considered that although it is confident that BETTA will go-live on 1 April 2005 as anticipated, contingency arrangements still need to be put in place. NGT considered that Option 1, which rolls over the existing E&W scheme until the delayed BETTA go-live date is the most appropriate. Extending the current arrangements and profiling them accordingly will cause minimal disruption. Furthermore, NGT stated that Option 1 was appropriate as it was developing its forecast from April 2005 on the basis of GB costs as a whole.

Other issues

Net Imbalance Adjustment

4.47. NGT highlighted that whilst it was committed to working with Ofgem on reviewing NIRP and the price adjusters, any change may have a large impact on the cost target.

Transmission Losses Adjustment

4.48. NGT echoed its views on NIA by stating that it recognised Ofgem's desire to align TLRP with the current forward price of electricity, but that a change to TLA may have a large impact on the headline cost figure for IBC. NGT was of the view that although changes to NIA and TLA may have large effects on the forecast value of IBC, neither NIA nor TLA are paid by customers as they do not feed through into BSUoS.

BSC Modification Proposals and CUSC Amendment Proposals

4.49. NGT considered that an allowance for CAP047 should be included in the 2005/05 GB SO incentive scheme.

4.50. NGT expressed concern that the planned consultation for CAP048 has not yet been issued by Ofgem, and considered that this should be resolved as soon as possible for E&W. In addition, NGT considered that it was unclear what effect CAP048 would have on Scotland as the security standards are different in E&W compared with Scotland.

4.51. In addition, NGT considered that those BSC Modification Proposals and CUSC Amendment Proposals that were not considered in the original cost forecasts should be explicitly excluded from the incentive scheme, and that the IAE provisions should be used. Furthermore, NGT considered that there should be careful consideration as to how all low probability - high impact events should be treated.

TO incentives

4.52. NGT considered that it will have the ability to request the movement of outages in Scotland, as it presently can in E&W. It is proposed that NGT will be given additional allowance in order to refund the Scottish TOs for their costs incurred in moving outages. As the ability for the GB SO to move outages in Scotland will be assumed when deriving forecast costs, it is not envisaged that any further adjustment should be made.

Summary

Respondents' views

4.53. Most respondents considered that the scope of the GB SO incentive scheme should be those costs which NGC has direct control over. It was unclear whether transmission losses, in particular, fell into this category.

4.54. Most respondents considered that, although an increased incentive could be created for NGC to drive down costs by lowering the IBC target, the current sliding scale incentive scheme mechanism should be retained.

4.55. The majority of respondents considered that it was inappropriate to implement anything other than a one year scheme from 1 April 2005, due to the uncertainty surrounding BETTA. However, several respondents expressed their support, in principle, for longer-term incentive schemes.

4.56. Respondents who directly commented considered it was necessary to have a contingency plan should BETTA go-live be delayed beyond 1 April 2005, although there was no clear consensus as to the most appropriate approach.

4.57. Several respondents considered it may be desirable to revisit the mechanisms for calculating NIRP and TLA.

NGT's views

4.58. NGT considered that the scope of its GB SO incentive scheme should be unchanged from that for E&W. The form of the GB SO incentive scheme may need reconsidering to accommodate the significant uncertainty associated with BETTA. NGT suggested that a deadband and asymmetric cap, floor and sharing factors should not be discounted. In addition, NGT considered that the scheme should be of one-year's duration due to the uncertainty, and favoured Option 1 to accommodate a contingency in the event that BETTA go-live is delayed.

4.59. NGT offered support for Ofgem's commitment to review NIA and TLA.

4.60. NGT considered that allowance should be made for CAP047 in the GB SO incentive scheme, and that the CAP048 consultation should be expedited.

5. NGT's projections of 2005/06 balancing costs

Introduction

5.1. This chapter provides information in relation to NGT's projections of IBC for Great Britain from 1 April 2005, as well as Ofgem's views in relation to these projections. Appendix 6 contains a paper prepared by NGT which outlines the basis for its forecasting approach and provides details relating to the forecast itself.

NGT's forecast costs for 2005/06

5.2. NGT's approach to projecting its IBC remains broadly the same as it has been for the preceding two SO incentive schemes, with the significant exception of including forecasts for balancing costs on a GB-wide basis.

5.3. For the incentive scheme to apply from April 2005, NGT has used its expected forecast of E&W balancing costs for the current incentive scheme period as a base case. From here, NGT considers how these costs may change as a consequence of defined cost drivers and moving to a GB-wide market, and then attempts to extrapolate future costs using this information.

5.4. As in previous schemes, NGT has created six scenarios for the costs of Balancing Mechanism actions and balancing services and has used these as the basis for its projections for the financial year from 1 April 2005 to 31 March 2006. NGT then used a Monte Carlo-type simulation approach[53] in conjunction with these scenarios to create a distribution of possible costs. These scenarios are based on six main drivers:

- forward prices;

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[53] Monte Carlo simulation involves taking a random value from each of the series of probability distributions for the input variables that determine the parameter being modelled (in this case NGC's balancing costs) and calculating the resulting parameter value. By repeating this process a large number of times (10,000 samples were used), a distribution for the output parameter can be created.

- Balancing Mechanism prices;

- plant margin (the difference between installed capacity (excluding mothballed plant) and forecast ACS winter peak demand expressed as a percentage of the installed capacity);

- free headroom (the volume of part-loaded plant that is able to respond within Balancing Mechanism timescales);

- net imbalance volume (this represents all energy and system balancing actions, netted off to give the energy imbalance for the whole system); and

- net flows across the French Interconnector.

5.5. When building its forecast IBC from April 2005, NGT has made the following assumptions:

- BETTA is fully implemented on 1 April 2005;

- NIRP is unchanged;

- TLRP is £21/MWh;

- CUSC Amendment Proposal CAP047 is active from October 2005; and

- No other material BSC Modification Proposal or CUSC Amendment Proposal arises.

5.6. NGT started the forecasting process by providing a comparison of the metrics of the geographical markets, as follows:

2003/04	**E&W**	**Scotland**	**Great Britain**	**Percentage of E&W**
Annual Energy (TWh)	309	34	343	+11.0
Peak Demand (GWh)	54.6	5.9	60.5	+10.8
Generation Capacity (GW)*	61.7	10.2	71.9	+16.5
Generation (TWh)*	305.3	42.2	337.5	+13.8

Notes: *E&W exclude interconnectors.

5.7. Under BETTA, NGC as GB SO will be required to carry out the balancing activities presently carried out by the Scottish Transmission Asset Owners (TOs), Scottish Power and Scottish and Southern Energy. At present, the costs of balancing the two Scottish networks are internalised by the Scottish TOs, and as a result are somewhat hidden. Under BETTA, however, these costs will be revealed under the GB SO incentive scheme – that is, they will be transparent.

5.8. Whilst NGT has suggested that the costs it will be exposed to will be greater than those incurred when undertaking balancing actions on an E&W basis, it has recognised that these costs will be less than if the costs of balancing the three TO networks were taken separately and summed together.

5.9. The key cost areas that NGT will be exposed to as a consequence of the implementation of BETTA are as follows:

- Response – under the British Grid Systems Agreement (BGSA), Scotland holds around 10.7 per cent of GB holdings, which is equivalent to 11.9 per cent of E&W holdings. Present response holdings are at 7.9TWh, so an 11.9 per cent increase will result in extra holdings of 940MWh.

- Reserve and margin – the GB operating reserve requirement will be based on plant breakdown and demand forecast errors in GB. This is the same approach as in E&W. NGC has forecast that the GB operating reserve will increase by around 310MW, to give a total GB-wide of around 3,800MW.

- Fast reserve – at present, although Scottish fast reserve units hold around one fifth of E&W holdings, NGT has forecast a proportional increase in the costs when procuring fast reserve on a GB basis. Total GB requirements are expected to remain at around 111 per cent of the current E&W level. NGT expects there to be more competition from Scottish Pumped Storage stations, and considerably more fast reserve will be held on these stations. NGT expects prices to move to align themselves with those seen posted by similar plant in E&W.

- Footroom – the volume of inflexible plant is expected to increase by between 3GW and 3.6GW. This is compared with an increase in overnight demand by between 2.6GW and 3.3GW. As a result there is a net increase of inflexible plant of around 0.4GW. Assuming one extra unit has to be taken off for around half of summer night time, this increases the footroom requirement by around 58 per cent to 570GWh.

- Reactive – data from the Scottish TOs shows reactive power to be around 4.6Tvarh. NGC has forecast this to rise to around 5Tvarh due to increased generation from Scottish wind generation. This increase is around one fifth of the requirement in E&W.

- Black Start – NGT expects there to be limited participation from Scottish units, although contracts are being negotiated

5.10. NGT has taken these additional factors into consideration when developing its scenarios for GB balancing costs. This process is the same as in previous schemes, and has generated the following outcomes:

Table 5.1 – NGT's scenarios

2005/06			Scenario Number and Probability						
			1	2	3	4	5	6	Mean
Driver of IBC		**As Was[1]**	**10 per cent**	**20 per cent**	**10 per cent**	**30 per cent**	**15 per cent**	**15 per cent**	
Forward Prices (£/MWh)		24	24	27	23	30	36	33	29
BM Prices (£/MWh)	**Offers**	54	54	58	53	61	66	63	60
	Bids	13	13	14	12	15	17	16	15
NIV (MW)*	**Summer[2]**	-600	-660	-540	-840	-610	-420	-480	-576
	Equinox	-500	-550	-450	-700	-510	-350	-400	-481
	Winter	-700	-770	-630	-980	-710	-490	-560	-672
Free Headroom (Daytime) (MW)[3]		1870	2050	1780	2430	1590	1500	1400	1716
Plant Margin (per cent)[4]		22	24	22	24	24	23	21	23
SP Average France to UK Flows (Wk Day Daytime) (MW)	**Summer**	-150	-150	0	-300	300	500	300	165
	Equinox	-330	-330	-124	-500	100	700	500	102
	Winter	550	500	700	300	900	1200	1000	820

1. Historic analysis is based on data from August 2003 to July 2004.
2. Summer = May to September, Equinox = March, April and October, Winter = November to February.
3. Free headroom indicates the volume of part-loaded plant that is able to respond within Balancing Mechanism timescales. Figures are for daytime.
4. **Plant margin is the difference between installed capacity (excluding mothballed plant) and forecast ACS winter peak demand expressed as a percentage of ACS winter peak demand.**

5.11. In reaching both the numbers and associated probabilities of each of its six scenarios, NGT has assumed a range of market conditions as detailed below:

- Scenario One assumes that there is no change in generator behaviour or generator ownership. Fuel prices fall to the level prior to the base period, restoring the price differential between E&W and Europe to that seen in the base period. The market gets slightly longer and free headroom increases slightly, as a result of the inclusion of additional Scottish generation.

- Scenario Two assumes some degree of market self-restraint, with some plant mothballing pushing down the margin. Easing fuel prices reduce some upward pressure on forward prices, which reach around £27/MWh. Higher forward prices and less volatile Balancing Mechanism prices increase market length overall and better despatch and risk management also means that the free headroom falls.

- Scenario Three assumes no mothballing or closure of plant, and the GB plant margin is unchanged at 24 per cent. Under BETTA, players aggressively target market share in E&W and in Scotland, and there is no meaningful market consolidation. Fuel prices fall and the impact of carbon trading is modest, such that forward prices fall to around £23/MWh. Lower Balancing Mechanism prices result from increased Balancing Mechanism competition, pushing up free headroom, and the low forward prices encourage market participants to go longer. Prices fall faster in GB relative to the continent, increasing flows across the interconnector.

- Scenario Four assumes the market behaves in much the same way as now, with high prices and high plant margin at the same time. Free headroom continues to fall at the present rate, despite the participation of Scottish generators. Balancing Mechanism prices continue to increase, reflecting higher forward prices. Market length remains more or less unchanged, as does the plant margin, and there is no mothballing or closure of plant.

- Scenario Five is based on continuing fuel price rises and high carbon costs. Reluctance to raise prices to domestic and industrial and commercial customers squeezes margins. Falling profitability forces less efficient plant to withdraw from the market, reducing the GB plant margin. The less efficient and marginal plant target the Balancing Mechanism for income and prices become more volatile. High forward prices and lower supplier profitability discourages suppliers from over-contracting, reducing the market length. Prices in GB are generally higher than on the continent resulting in moderate imports.

- Scenario Six assumes that the introduction of BETTA results in gradual consolidation into a few large players. Less efficient plant is withdrawn from the market and the plant margin falls to 21 per cent. The fuel price remains moderately high and the impact of carbon trade is moderate, resulting in forward prices of £33/MWh. High forward prices prevent suppliers from over-contracting resulting in a reduction in market length. Higher wholesale prices put pressure on Balancing Mechanism prices, which rise accordingly. With more consolidation generators build on their past operating experiences and achieve further reductions in free headroom.

5.12. To each of these scenarios, NGT has attached what it considers to be a plausible probability figure ranging from ten per cent for scenarios 1 and 3, 15 per cent for scenarios 5 and 6, 20 per cent for scenario 2 and 30 per cent for scenario 4, although there is no detailed analysis to support these figures. NGT has stated that these probabilities were arrived at by extensive discussion between experts within NGT.

5.13. To translate the scenarios into cost projections, NGT has started from a detailed breakdown of its outturn costs between 1 August 2003 and 31 July 2004. It has then applied scenario-specific scaling factors for both volumes and prices to calculate cost estimates, and has added the calculated costs to its prediction of E&W balancing costs for 2004/05 of £394.9 million. Table 5.2 shows NGT's projections for 2005/06 by scenario, and the probability-weighted mean of the scenario values by component.

Table 5.2 – NGT's estimates for 2005/06 by scenario (£ million, money of the day)

Cost element	Scenario						Mean
	1	2	3	4	5	6	
IBMC plus trading less constraint costs	75.1	87.1	68.4	92.0	97.9	105.1	89.8
Ancillary service costs less constraints	247.1	250.8	241.4	258.7	269.6	265.6	256.9
Transmission losses	120.8	122.9	128.9	121.8	119.1	123.9	122.5
Constraint costs	64.2	80.6	91.9	72.0	66.1	71.2	73.9
Total	**507.3**	**541.4**	**530.5**	**544.5**	**552.6**	**565.8**	**543.2**

5.14. The probability-weighted mean of NGT's projections of IBC for 2005/06 is £543.2 million. This projection is around £128 million higher than the target for the current incentive scheme (£415 million) and is over £148 million higher than NGT's own forecast of E&W balancing costs for 2004/05.

5.15. The key cost changes to NGC's balancing services categories outlined in Table 5.3.

Table 5.3 – Historic comparison of NGT's balancing services costs by incentive scheme period (£ million, money of the day)

Balancing Service	2001/02 (E&W)	2002/03 (E&W)	2003/04 (E&W)	2004/05 (E&W)	2005/06 (GB)	Difference (2005/06-2004/05)
Reactive Power	38.1	33.0	33.5	39.0	58.5	19.5
Standing Reserve	22.0	30.5	53.5	56.0	67.4	11.3
Fast Reserve	50.3	42.75	27.2	29.3	29.4	0.1
Other Reserve	6.6	4.5	4.2	4.9	5.8	0.9
Margins	26.2	85.8	86.5	88.3	109.1	20.8
Response	78.8	74.5	55.7	62.7	87.2	24.5
Footroom	20.3	5.8	6.1	5.7	7.6	1.9
Other	30.1	37.3	25.1	35.7	36.8	1.1
Constraints	9.3	28.0	31.6	18.0	73.9	55.9
Transmission losses	91.5	80.8	76.6	95.0	122.5	27.5
Energy Balancing	-7.9	-38.6	-43.1	-39.7	-55.0	-15.3
Total	365.3	384.3	356.8	394.9	543.2	148.2

5.16. The rationale provided by NGT for the changes to the cost components in Table 5.3 is summarised below:

- Reactive Power – increase of £20 million due to new payment to Scottish power output, and rise in default utilisation price.

- Standing Reserve - increase of £11 million as a result of greater volume requirement.

- Margins – increase of £21 million as a result of higher operating margin requirement on a GB basis.

- Response – increase of £24 million, including an allowance of £15 million for CAP047 and increase in overall Scottish response costs.

- Constraints – increase of around £56 million, mainly originating at the Cheviot boundary (previous Anglo-Scottish interconnector) and within Scotland.

- Transmission Losses – increase of around £28 million as a consequence of including Scottish losses.

- Energy balancing – overall increase in saving as a result of increased Balancing Mechanism bid prices reflecting fuel price increases, and a longer market due to the enlargement of the market.

5.17. The cost increases for the GB SO incentive scheme from 1 April 2005, are allocated as detailed in Table 5.4 below.

Table 5.4 – Allocation of cost increases (money of the day)

Category	**Cost**
2004/05 IBC for E&W	**£395 million**
Moving to a GB-wide market	**+£61 million**
♦ IBMC + Ancillary Services	+£34 million (+12% on E&W)
♦ Transmission Losses	+£27 million (+28% on E&W)
Constraints	**+£55.9 million**
♦ Within Scotland and Cheviot	+£53.9 million
♦ E&W	+£2 million

Category	Cost
Cost Pressures on Existing Activities	**+£31.3 million**
♦ Reactive	+£9.5 million (CAP045)
♦ Reserve/Margin	+£13 million (less free headroom)
♦ CAP047	+£15 million
♦ Others (including energy balancing)	-£6.2 million
2005/06 IBC for GB	**£543.2 million**

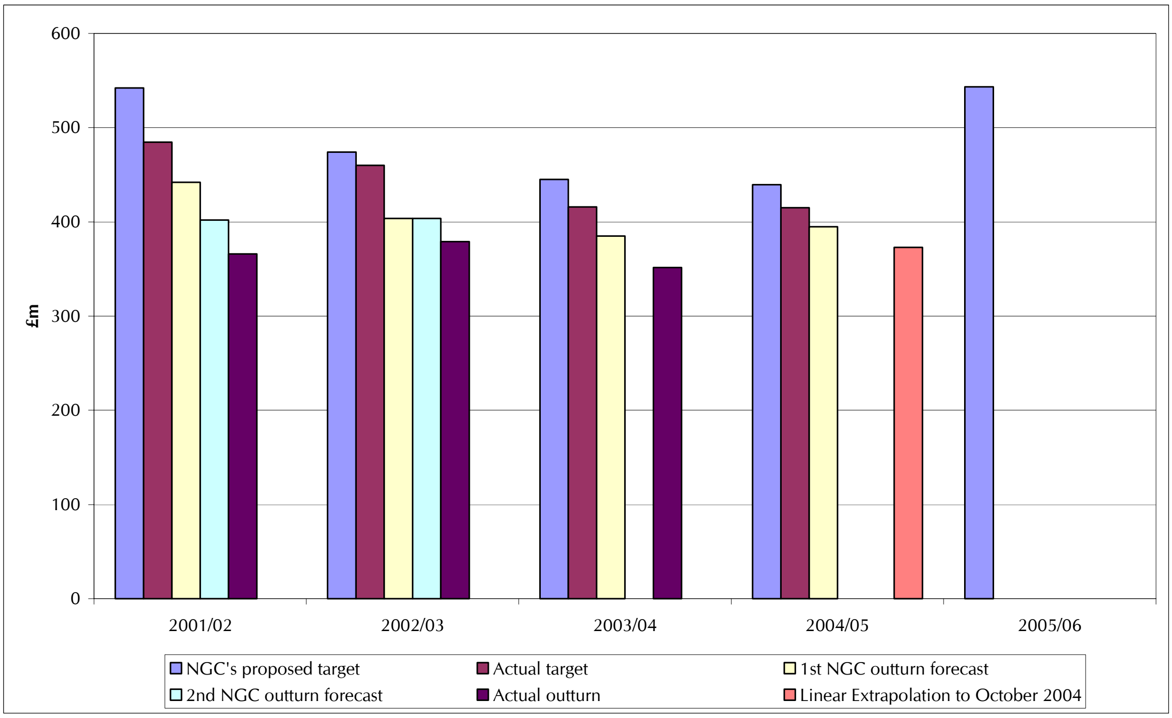
5.18. As mentioned above, Appendix 6 contains a paper prepared by NGT which outlines the basis of forecasting approach and details relating to the forecast itself. Ofgem welcomes views in relation to NGT's forecasting approach and assumptions, as well as in relation to the details of the overall forecast and its sub-components.

Ofgem's views of NGT's forecast costs for 2005/06

5.19. This section outlines Ofgem's views in relation to NGT's forecast of GB balancing costs for 2005/06. These views have been formed on the basis of analysis and assessment of NGT's forecasts to date. It is important to note that this process is still ongoing and will continue for the coming months until final proposals are developed. It is therefore possible that Ofgem's views on issues outlined below may change and equally that additional issues may arise which will influence Ofgem's views of NGT's forecast.

5.20. In considering NGT's forecast for 2005/06, Ofgem is mindful of the historic comparison between NGT's forecasts of IBC ahead of an incentive scheme and its actual outturn costs under the relevant incentive scheme. As already outlined in chapter 3, in previous schemes, NGT's forecasts of IBC have been substantially above the target Ofgem has set for NGC and NGC has been able to consistently out-perform against the target set by Ofgem. Therefore, as expanded upon further below, Ofgem has concerns about the overall level of NGT's forecast, in the light of evidence to date.

Figure 5.1 – Comparisons of NGT forecasts with outturn IBC costs[54] (money of the day)



5.21. Figure 5.1 shows the difference between NGT's pre-incentive IBC forecasts, its mid-incentive IBC forecasts and outturn IBC mentioned above. For example, including the current incentive scheme period, in all four years, NGC's initial target forecast has been between 11 per cent (2004/05) and 23 per cent (2001/02) higher than the estimate of outturn IBC it has subsequently made during the autumn of the incentive scheme period[55]. Moreover, the autumn estimates have also consistently turned out to be too high, by at least six and a half per cent, with Ofgem's view being that this is likely to continue for the current incentive scheme period. Thus, for the first three incentive schemes, NGT's proposed targets have turned out to be higher than outturn costs by 48 per cent, 25 per cent and 27 per cent respectively.

5.22. In the case of the current incentive scheme, the deviation between NGC's 2004/05 IBC forecast of £439.4 million and NGC's projected outturn of £394.9 million is ten per cent, rising to 15 per cent if the linear extrapolation of £373 million is considered. However, NGT's 2004/05 IBC forecast of £439.4 million was based on an assumed TLRP of £17/MWh, whereas the actual TLRP for the

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[54] NGC's proposed target for 2005/06 is for a GB market.

current period is £21/MWh. If the actual TLRP value in operation is considered, NGT's 2004/05 IBC forecast increases from £439.4 million to £457.5 million. The deviation between this value of £457.5 million and NGC's projected outturn of £394.9 million is 14 per cent, rising to 18 per cent if the linear extrapolation of £373 million is considered.

5.23. While the deviation between NGC's pre-scheme forecast and actual/predicted outturn is reducing, in the case of the current incentive scheme the ten to 14 per cent deviations identified translate into a difference of £44.5 million to £62.6 million. This represents a substantial difference in monetary terms. Ofgem considers that there is at least some evidence to suggest that the methodology used by NGT to produce its forecast is biased and consistently overestimates the mean of the distribution of costs.

5.24. Having outlined this broad concern that the methodology used by NGT has historically provided forecasts that may have overstated costs, the sections below outline specific aspects of NGT's forecast in relation to which, on the basis of assessment to date, Ofgem considers there to either be scope for cost savings or where NGT's cost projections appear to be overstated.

Starting point

5.25. As outlined above, the starting point for NGT's projected SO incentive scheme target for 2005/06 is its latest forecast of outturn IBC for 2004/05. NGT's latest forecast of outturn for the current incentive scheme period is £394.9 million. This is over £43 million higher than the actual outturn IBC figure for the previous period of £351.5 million (although £18 million of this can be linked to the increase in TLRP from £17/MWh in 2003/04 to £21/MWh in 2004/05) and compares to a linear extrapolation of NGC's actual end of year IBC of around £373 million based on data up to the end of October 2004. Ofgem notes that, as briefly mentioned above, NGT's autumn forecasts of outturn IBC for the relevant incentive period have consistently overestimated actual outturn IBC.

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[55] For example, the forecast for 2002/03 and the estimate for 2002/03 made in autumn 2002.

5.26. In the context of previous schemes NGT's forecast of outturn costs has been six and a half per cent to 20.8 per cent above actual outturn IBC[56]. The following bullets illustrate how different over-forecast assumptions, based on the range of actual over-forecasts seen in the previous two incentive schemes, affect the starting point for 2005/06 costs:

- a six and a half per cent over-forecast reduces the starting point from £395 million to £371 million
- a 7.5 per cent over-forecast reduces the starting point from £395 million to £367 million
- an 8.5 per cent over-forecast reduces the starting point from £395 million to £364 million
- a 9.5 per cent over-forecast reduces the starting point from £395 million to £361 million

5.27. Ofgem's initial views on the 2005/06 scheme are, in part, informed by the historic over-forecasting by NGC in the range of between 6.5 and 9.5 per cent.

5.28. At this stage, Ofgem's proposed approach to this issue is discussed further in the next chapter. Ofgem would welcome views from respondents in relation to any views that they may have on NGC's historic over-forecasting and how this may inform what should be the appropriate starting point for the 2005/06 scheme.

5.29. On the basis of the existing starting point of £394.9 million, NGT's proposed target for operating the GB transmission system for incentive scheme period 2005/06 is £543.2 million. NGT has constructed this figure by taking a forecast of E&W outturn IBC for the current period and adjusting this to reflect Scottish balancing costs and existing cost drivers on both E&W and Scottish balancing costs.

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[56] In the 2001/02 scheme, NGT's initial forecast of costs was 20.8 per cent above actual outturn costs while its second forecast was 9.8 per cent above outturn. In the 2002/03 scheme, NGT's forecast of costs was 6.5 per cent above actual outturn. In the 2003/04 scheme, NGT's forecast of costs was 9.5 per cent above actual outturn.

5.30. NGT's incremental allowance for incorporating Scotland and the effects of existing cost drivers is around £148.3 million, which represents an increase over its forecast E&W costs of around 38 per cent. The size of the Scottish market compared to E&W is around 11 per cent when comparing annual energy, and around 14 per cent when comparing generation volume. It is, therefore, clear that the forecast increase in balancing costs is considerably greater than the relative increase in the size of the market. Ofgem is concerned that NGT's proposed target of £543.2 million is considerably higher than would appear to be justified by the increase in the size of the market. In addition, Ofgem has expressed concerns that the costs of operating the GB transmission system should be less than would be the case of adding the balancing costs of the three transmission asset owners, due to the synergies arising in moving from an E&W system to a GB-wide system.

5.31. At this stage, Ofgem has specific reasons for considering that NGT's forecast may be an over-estimate. In the following section Ofgem notes its concerns regarding NGT's forecasts of constraint costs, forward prices, Balancing Mechanism bid and offer prices and ancillary services costs.

Constraints

5.32. For the current incentive scheme period, NGT's mean forecast of constraints over the course of the year was around £50.7 million[57], without accounting for the benefit of TS Capex. With TS Capex, NGC's forecast of constraints for 2004/05 was around £40.7 million. As part of the process to determine what GB balancing costs should be in 2005/06, NGT is forecasting that constraints for the current incentive scheme period will in fact be around £18 million, indicating that the forecast of £40.7 million was an overestimate of around 126 per cent. For 2005/06, NGT has made an allowance of £20 million[58] for constraints in E&W, and a further £53.9 million for constraints relating to accommodating Scotland. In short, NGT's forecast of constraints has risen from £18 million for 2004/05 on an E&W basis, to £73.9 million on a GB basis. This

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[57] This forecast is £10 million higher than NGT expected constraint costs to be because it is based on an estimate of what they would be if it had not undertaken constraint-related capital expenditure in excess of the allowance included in the SO internal costs incentive (for "TS capex").
[58] This includes an increase for E&W of £2 million over the previous scheme.

represents a trebling of overall constraint costs, while the increase in annual demand is around 11 per cent, NGT splits this figure into E&W at £20 million, the Cheviot boundary at £37 million and within Scotland at £17 million. Within Scotland constraints were forecast in a similar manner to E&W constraints, derived from a breakdown of costs on a locational basis.

5.33. As a consequence of all parties being granted access to the GB transmission system if they apply prior to 1 January 2005, it is likely there will be significant constraint costs arising from their accommodation, especially across the ex Anglo-Scotland interconnector, known as the Cheviot boundary.

5.34. The rationale provided by NGT for the cost of constraints across the Cheviot boundary includes an assumption that the capacity of the boundary is 2.2GW in winter, 2GW in summer under intact conditions and 1.2GW under outage conditions. A total of 14 weeks of outages across the boundary have been assumed, including ten weeks necessary for works associated with Renewable Energy Transmission Study (RETS). There is no provision for an intertrip across this boundary, and there will be an additional 1.4GW of windfarms commissioning by Autumn 2005/06, with an assumed load factor of 35 per cent. In relation to the cost of constraints within Scotland, NGT has used a bottom-up approach similar to that used for E&W constraint cost forecasting, taking into account latest outage plans and estimates of the risk and impact of station closures.

5.35. Ofgem notes that there are considerable uncertainties associated with constraint cost forecasting for the 2005/06 period. One such uncertainty at the present time is linked to the level of windfarm generation which is likely to be operating in Scotland during 2005/06 and the timing at which this generation is likely to come on stream. In addition, NGC does not have operational experience of managing constraints in Scotland.

5.36. Ofgem is still assessing NGT's constraint cost forecasts and will continue to do so over the coming months. However, Ofgem's current position is that NGT's forecast of £73.9 million for constraint costs on a GB basis appears excessive, particularly in the case of the costs associated with the within Scotland constraints and the Cheviot boundary constraints.

5.37. At this stage, Ofgem considers that there is scope for the within Scotland constraint cost forecast to be reduced by 50 per cent (a similar reduction can be seen in the difference between NGC's E&W constraint cost forecast and its projected constraint cost outturn in the current incentive scheme period). This would leave the within Scotland constraint cost allowance at £8.5 million. In relation to the Cheviot boundary constraints, Ofgem accepts that there is likely to be a considerable volume of constraints across the Anglo-Scottish border. However, Ofgem is concerned that the associated constraint cost forecast of £37 million is excessive. Ofgem considers that there is scope for the Cheviot boundary constraint cost to be reduced by as much as 50 per cent, leaving an allowance of £18.5 million.

5.38. As mentioned previously, Ofgem is continuing to consider NGT's constraint forecasts, particularly focussing on the Cheviot boundary and within Scotland aspects. Ofgem's proposed approach at this stage to this issue is discussed further in the next chapter. Ofgem would welcome views from respondents in relation to the appropriateness of NGT's constraint cost forecasts and the scope for reductions in these forecasts.

Forward prices

5.39. Ofgem is concerned that the forward prices assumed in the scenarios may well be considerably higher than current trends for the 2005/06 period indicate. Ofgem notes that forward prices over recent months for packages in 2005/06 have been over £30/MWh and were around £35/MWh in October 2004. However, forward prices have now fallen below £30/MWh to around £28/MWh and the current trend indicates further downward movement. The range of prices assumed in NGT's scenarios is between £23/MWh and £36/MWh. Ofgem is particularly concerned that only one of the scenarios sees prices return to the 'as was' levels highlighted within NGT's forecast and that this scenario has a weighting of 10 per cent. Ofgem notes that NGT's scenarios assign a 30 per cent weighting to prices between £33/MWh and £36/MWh and a 30 per cent weighting to prices of £30/MWh, despite the current downward trend in forward prices. Ofgem will continue to review the forward price trends over the coming months. However, at present, Ofgem is concerned that given recent movements in forward prices, some of NGT's scenarios may overestimate forward prices.

5.40. The impact of NGC's forecast high forward prices feeds directly through into several calculations, such as the default reactive price under CUSC Amendment Proposal CAP045 and the calculation of Cheviot constraint costs. The default reactive price is calculated on a 50 per cent weighting to power exchange prices and 50 per cent to the Retail Price Index (RPI). Ofgem is concerned that the costs associated with reactive power are higher than might be expected because 50 per cent of the price is weighted to an average scenario forward price of £29/MWh. Ofgem considers that reactive power costs could be overestimated as a result of using this forward price. In addition to the concerns previously expressed about the derivation of constraints, the replacement energy costs across the Cheviot border are weighted 75 per cent to NGC's scenario forward price, and 25 per cent to NGC's forecast offer price. Ofgem therefore considers that it is possible that the costs of replacement energy have been over-stated.

CAP047

5.41. NGC has modelled the effect of operating a frequency response market under CUSC Amendment Proposal CAP047 from October 2005 to the end of March 2006. NGC has assumed that on average, over this period of time, market participants raise their prices by 50 per cent, such that the cost of response holdings rises from around £29.4 million to £44.1 million – an increase of £14.7 million. NGC has not modelled any downward pressure on costs that may arise as a consequence of the market being open to competition and including Scottish generation plant.

5.42. In its decision letter relating to Amendment Proposal CAP047, Ofgem acknowledged that there is likely to be a degree of price exploration following its implementation. However, Ofgem considers that this exploration will be more limited than that envisaged in NGT's projections. Therefore, Ofgem does not consider that an aggregate price increase of 50 per cent will materialise as projected by NGT. If we were to assume a ten per cent increase in the prices submitted by market participants, there would (on the basis of NGT's model) be a £2.9 million increase in costs rather than £14.7 million as projected by NGT. The forecast increase in costs rises to £7.3 million if a 25 per cent increase in prices is considered.

5.43. Ofgem's proposed approach at this stage to this issue is discussed further in the next chapter. Ofgem would welcome views from respondents in relation to the appropriateness of NGT's projection that holding prices would increase by 50 per cent following the implementation of CAP047 and of any downward adjustment in this projection.

Supplemental standing reserve

5.44. In NGC's calculation of standing reserve costs, NGC has assumed that it may procure a similar volume of supplemental standing reserve (SSR) on a GB basis as it has done for E&W of around 850MW. NGC has assumed that the effect of Scottish competition offsets a perceived upward movement in prices, and results in the cost of procuring reserve remaining the same, at around £17.6/kW. NGC has therefore forecast a total cost of procuring SSR of around £15 million. Ofgem considers that the effect of Scottish competition when procuring a similar level of SSR from a larger pool of available plant would be to put downward pressure on prices and therefore costs. As the 2004/05 SSR Tender was instigated at a time when market expectation was that prices would rise substantially, Ofgem expects that the price of £17.6/kW could be considerably above that which could prevail in 2005/06. If a price of around £14/kW is assumed, the costs of 850MW of SSR would be reduced to around £12.9 million – a reduction of over £2 million.

Interconnector flows

5.45. In light of the high forward prices that NGC has forecast for its scenarios, Ofgem would expect that there would be more response in terms of French interconnector flows. Ofgem is particularly concerned that in scenario 5, which carries the average annual forward price of around £36/MWh, NGC has assumed that the interconnector would import between 500MW and 1200MW, depending on the time of year. Ofgem considers that the severe prices that would need to prevail throughout the course of the year, and especially at peak times, to generate an annual forward price of around £36/MWh, would result in considerably increased import from the continent than NGC suggests. As NGC has suggested in previous incentive schemes, and in other areas of its forecasts for the forthcoming scheme, the French interconnector is relatively responsive to price differentials. As NGC has elsewhere suggested that the prices in GB rise faster than on the continent, Ofgem would expect there to be greater import across the French interconnector and for there to be more available plant, and therefore a higher plant margin.

Balancing Mechanism prices

5.46. Ofgem further has concerns that the offer and bid prices presented in its scenarios may over-estimate the increase in the offer price, relative to the bid price, such that the costs of Balancing Mechanism actions increase. NGC has stated elsewhere that the driver of high forward prices is the cost of fuel inputs. With this being the case, Ofgem would expect there to be a larger increase in the bid price, which represents the marginal cost of production, and that generators would face a squeeze on margins due to competitive pressures preventing the offer price from rising too high.

Headroom and footroom

5.47. Ofgem also considers that there needs to be more information provided on the determination of headroom and footroom actions. Whilst Ofgem accepts that the historic trend for headroom has been downwards due to improved despatch by generators and suppliers, there is little evidence to suggest that this trend will continue in a GB environment. In addition, Ofgem is concerned that the increase in footroom actions of around 58 per cent, associated with a net increase in inflexible plant of around 0.4GW may be overstating the effect of this additional plant.

Summary

5.48. At this stage in its assessment of NGT's forecast costs for 2005/06, Ofgem considers that there are several areas in which NGT's projections over-estimate costs. Ofgem will continue its assessment of NGT's forecast over the coming months. In the meantime, Ofgem would welcome views from respondents in relation to NGT's forecast and the issues highlighted by Ofgem in this chapter.

5.49. The next chapter outlines Ofgem's proposals for NGC's external SO incentive scheme from 1 April 2005 at this stage.

6. Ofgem's Initial Proposals for the GB SO incentive scheme to apply from 1 April 2005

Introduction

6.1. This chapter outlines Ofgem's Initial Proposals in relation to NGC's external SO incentive scheme from 1 April 2005. The proposals are intended to maintain and, where appropriate, improve the incentives on NGC to operate and develop the transmission system in an economic, efficient and co-ordinated manner, which is in the interest of customers, who ultimately pay for the costs of system operation.

6.2. These proposals have been developed in light of NGC's operational experience under NETA, respondents' views on the Initial Consultation and Ofgem's own views of NGT's forecast of IBC.

Scope of the GB SO incentive scheme to apply from 1 April 2005

Ofgem's Initial Proposals

6.3. Ofgem proposes that the existing scope of the E&W SO incentive scheme (i.e. covering all electricity and system balancing costs which are within the SO's control) provides an appropriate basis upon which to develop GB SO incentive arrangements and as such should be retained.

6.4. However, Ofgem notes that several respondents questioned the appropriateness of the scope of the existing scheme. In particular, several respondents considered that the scope should be reduced to exclude those balancing services where competitive provision ensures that NGC procures the services economically and efficiently, thereby removing the need for incentive arrangements. Ofgem agrees that competition in the provision of balancing services should lead to a reduction in the price at which NGC procures the service. However, in the absence of incentives in relation to the overall cost of procuring balancing services, NGC would not have commercial incentives to procure an efficient volume of balancing services. Therefore, even when the price of balancing services is efficient due to competitive provision, Ofgem considers that commercial incentives are still appropriate in order to ensure that an efficient volume of balancing services is procured and hence to manage the overall costs of balancing services procurement.

6.5. Ofgem also notes that the inclusion of transmission losses within the incentive scheme was questioned by several respondents. This element of the scheme is intended to provide the SO with incentives to manage the volume of transmission losses that are consistent with its balancing incentives. NGC can influence the volume of transmission losses through its choice of balancing actions. For example, if NGC is considering two possible actions for energy balancing purposes which have equivalent characteristics (e.g. in terms of price, dynamics, etc) but would be provided from different geographic locations, NGC has the ability to select the option which has the lowest associated transmission losses volume. On this basis, Ofgem considers that it is appropriate for the transmission losses element to be included within the incentive scheme. However, as will be discussed further later in this chapter, Ofgem is considering a potential revision to the way in which the transmission losses element feeds into the overall incentive scheme.

6.6. Therefore, Ofgem's initial proposal is that the scope of the GB SO incentive scheme should be consistent with that of the existing E&W SO incentive scheme.

Views invited

6.7. Ofgem welcomes views on the following:

- its initial proposal that the scope of the GB SO incentive scheme should be consistent with the scope of the existing E&W SO incentive scheme.

Form of the GB SO incentive scheme to apply from 1 April 2005

Ofgem's Initial Proposals

6.8. Ofgem continues to consider that it is appropriate for NGC's SO incentive scheme to be a sliding scale scheme, with a single target value and symmetry between the cap and floor values and between the sharing factors. Ofgem notes that the majority of respondents supported the retention of a sliding scale incentive. As such, Ofgem's initial proposal is that the GB SO incentive scheme to apply from 1 April 2005 should be a sliding scale scheme.

6.9. However, Ofgem also continues to consider that there may be some uncertainty associated with the level of balancing costs under BETTA, although significantly less than was the case ahead of NETA go-live for the following reasons (as outlined in the Initial Consultation):

- that NGC and market participants more generally now have approximately three and a half years of experience of operating under the trading arrangements which were introduced at NETA go-live and which will be extended at BETTA go-live;
- that in advance of NETA go-live, the SO incentive arrangements were being developed to apply within the context of new trading arrangements, whereas, as part of BETTA, the existing arrangements are being extended to apply across GB rather than being developed afresh; and
- the relative sizes of the E&W and Scottish sections of the GB market (in 2003/04 peak demand was 53.1GW in E&W compared to 5.9GW in Scotland and installed capacity was 65.1GW in E&W compared to 12.2GW in Scotland).

6.10. To the extent that uncertainty does exist, Ofgem considers that it is appropriate for this to be reflected in the form of the SO incentive arrangements. Ofgem suggested several mechanisms in the Initial Consultation which could be adopted to accommodate any uncertainty. Ofgem's Initial Proposals in relation to these options are as follows:

- **separate SO schemes for Scotland and E&W:** Ofgem notes that respondents agreed with Ofgem that a single GB wide scheme should be employed, as separate schemes could create perverse incentives between the different incentive arrangements. Ofgem continues to consider that it is important for the GB SO role to have a single incentive scheme to ensure consistent incentives apply across GB. Therefore, Ofgem's Initial Proposals are that a single GB wide scheme should be developed and implemented.

- **deadband target range:** Ofgem notes that, with the exception of NGT, those respondents that directly commented on this issue did not support the reintroduction of a deadband target. NGT considered that the option of a deadband should be retained. Ofgem's preference at this stage is that a deadband target range should not be reintroduced as this creates a range of costs within which NGC has reduced incentives to manage costs on behalf of customers. Therefore, Ofgem's Initial Proposals do not include a deadband target range.

- **asymmetric cap, floor and sharing factors:** Ofgem has previously expressed its preference for symmetry in relation to sharing factors and to cap/floor values. However, Ofgem considers that reducing the downside exposure of the incentive scheme relative to the upside reward represents the most appropriate option to accommodate within the incentive scheme any perceived uncertainty in relation to GB SO costs. As discussed further later in the chapter, Ofgem's Initial Proposals do include asymmetric cap, floor and sharing factors.

Views invited

6.11. Ofgem welcomes views on the following:

- its initial proposal that a sliding scale incentive scheme should be developed;

- its initial proposal that a single GB wide SO incentive scheme should be developed;
- its initial proposal that a deadband target range should not be considered; and
- its initial proposal to allow asymmetric cap, floor and sharing factors in order to accommodate any perceived uncertainty in relation to GB SO costs.

Duration of the GB SO incentive scheme to apply from 1 April 2005

Ofgem's Initial Proposals

6.12. Ofgem proposes that the GB SO incentive scheme to run from 1 April 2005 should be one year in duration. Ofgem agrees with the majority of respondents who considered that the lack of operational experience under BETTA makes it difficult to develop a two year scheme at this stage. Ofgem is, therefore, seeking to develop a one year scheme which accommodates any uncertainty associated with the GB balancing costs. Looking forward, however, Ofgem remains of the view that the duration of NGC's SO incentive schemes should be lengthened and made consistent with the duration of NGC's TO price control, as outlined in the September 2004 Initial Consultation.

Views invited

6.13. Ofgem welcomes views on the following:

- its initial proposal that the duration of the GB SO incentive scheme to apply from 1 April 2005 should be one year in duration.

Incentive scheme parameters

Ofgem's Initial Proposals

Net Imbalance Adjustment

6.14. Ofgem notes that the majority of respondents who commented considered that it would be appropriate to revise the rules describing the calculation of the Net Imbalance Adjustment (NIA) parameter following the merger of UKPX and APX. Ofgem's initial proposal is to revise the associated licence drafting to reflect that there is now only one market index data provider in this respect.

6.15. Ofgem also highlighted in the Initial Consultation the option of reviewing the price adjuster components of NIA. Ofgem notes that this suggestion received only limited feedback from respondents. On the basis that the transition to a GB SO incentive scheme creates the potential for uncertainty in relation to GB balancing costs, Ofgem considers that it may be prudent to leave the price adjuster components unchanged for the forthcoming year to avoid creating the potential for additional uncertainty in the context of the GB SO scheme. Therefore, Ofgem's initial proposal is to leave the price adjusters unchanged for the incentive scheme to apply from 1 April 2005. However, Ofgem expects to review these parameters in the context of future SO incentive schemes.

Transmission Losses Adjustment

6.16. Ofgem notes that respondents agreed that Scottish and E&W transmission losses should be included within the same incentive package to provide consistent incentives in respect of transmission losses across the whole of GB. Therefore, Ofgem's initial proposal is that a single Transmission Losses Adjustment (TLA) should be developed. Under this approach, NGC would have a single GB transmission losses volume target and a Transmission Losses Reference Price (TLRP) which would be applied consistently to the finalised GB transmission losses target.

6.17. As in previous years, to ensure that the transmission losses element of NGC's SO incentive scheme is consistent with the balancing services element, Ofgem proposes that TLRP should be set to reflect market prices on the basis of the prevailing forward curve for the timescale in question. On the basis of current prices for the annual period beginning on 1 April 2005, TLRP should be set above the existing £21/MWh, which would be expected to substantially increase the TLA component of IBC.

6.18. However, as highlighted by NGT in its response, it is important to note that TLA is not actually paid for by customers, as it is not a component of BSUoS charges[59]. It is the impact of the difference between TLA outturn and the TLA allowance on NGC's overall incentive payment/receipt to which customers are exposed. However, as indicated above, under the existing approach changes to the components of TLA can potentially have a considerable effect on the headline IBC number even though this is not a cost to which customers are exposed.

6.19. Ofgem considers that the inclusion of the gross value of losses within IBC, as at present, may be misleading in terms of the costs to which customers are actually exposed. Ofgem is, therefore, considering a potential revision to the way in which TLA feeds into overall IBC.

6.20. As mentioned above (and as outlined in Appendix 1), at present the gross value of losses feeds into IBC as follows:

$$IBC = CSOBM + BSCC + (TL*TLRP) + (TQEI*NIRP) - RT - OM$$

6.21. An alternative option is to include the net value of losses in IBC as follows, where TLT is the Transmission Losses Target:

$$IBC = CSOBM + BSCC + ([TL-TLT]*TLRP) + (TQEI*NIRP) - RT - OM$$

6.22. The following example shows that the gross and net schemes would lead to the same result in terms of the incentives provided for NGC to manage transmission losses volume. If its is assumed that:

- TLRP = £20/MWh
- forecast TL = 5.0TWh

[59] The same applies for NIA which is also not a component of BSUoS charges.

- outturn TL = 4.8TWh
- IBC target excluding losses = £300 million
- outturn IBC excluding losses = £300 million (i.e. all other costs outturn in accordance with the allowances made in the target)

6.23. Under a gross losses scheme:

- overall IBC target = £300 million + (5.0TWh * £20/MWh) = £400 million
- overall outturn IBC = £300 million + (4.8TWh * £20/MWh) = £396 million
- incentive payment to NGC = £4 million * upside sharing factor

6.24. Under a net losses scheme:

- overall IBC target = £300 million + £0 million = £300 million (i.e. TLA would be expected to outturn at zero and so there would be no allowance in the target)
- overall outturn IBC = £300 million + ((4.8TWh – 5.0TWh) * £20/MWh) = £296 million
- incentive payment to NGC = £4 million * upside sharing factor

6.25. Therefore, both schemes are identical in terms of their incentive properties, whilst the net scheme offers the advantage that IBC outturn and target values more accurately reflect the costs actually borne by customers.

6.26. For information, Table 6.1 below shows the difference in IBC in the previous and existing SO incentive schemes when the net value of losses is included versus when the gross value of losses is included.

Table 6.1 – Impact of gross value of losses versus net value of losses on SO external cost incentive target since NETA go-live (money of the day)

Parameter	2001/02 scheme[60]	2002/03 scheme	2003/04 scheme	2004/05 scheme
Target IBC with gross TLA	£484.6 million to £514.4 million	£460 million	£416 million	£415 million
Gross TLA	£20.30/MWh * 5.05TWh = £102.5 million	£18.50/MWh * 5.05TWh = £93.4 million	£17.00/MWh * 4.50TWh = £76.5 million	£21.00/MWh * 4.53TWh = £95.1 million
Target IBC with net TLA	£382.1 million to £411.9 million	£366.6 million	£339.5 million	£319.9 million

6.27. To summarise, Ofgem's Initial Proposals in relation to transmission losses are:

- that GB transmission losses will be treated within the same scheme with a single target volume and a single TLRP; and
- that consideration will be given to whether a net losses scheme is more appropriate than a gross losses scheme.

Target

6.28. In developing its Initial Proposals, Ofgem has sought to develop a reasonable and proportionate target that provides an appropriate balance between the need to continue to build on the effective incentive schemes under which NGC has operated in its SO role in E&W to date and the need to reflect any uncertainty associated with the extension of its role to apply GB-wide. The paragraphs below outline Ofgem's Initial Proposals in relation to the incentive scheme target.

6.29. NGT's projected target for the 2005/06 incentive scheme is £543.2 million as opposed to this year's target of £415 million. Ofgem acknowledges that part of the year-on-year increase reflects the expansion of the geographic scope of NGC's SO role to include Scotland and the resultant internalisation of existing

[60] The figures presented in relation to the initial incentive scheme represent the finalised parameters for the scheme following adjustments to reflect that the scheme was 370 days in duration, not 365 days, and

Scottish balancing costs within the SO incentive scheme. Ofgem noted in the previous chapter potential deviations from NGT's projected target value that it considers to be appropriate at this stage. This is based on the assessment that Ofgem has completed upon NGT's information submission to date. As this process is still ongoing, it should be noted that the views are subject to revision on the basis of further assessment and clarification on the relevant issues.

6.30. On the basis of the issues highlighted previously, Ofgem considers that there is justification for a lower target value than the £543.2 million figure proposed by NGT. Assuming a gross transmission losses scheme incorporating a TLRP of £21/MWh and a volume target of 5.8TWh, Ofgem considers that a target range between £467.8 million and £482.4 million may be more appropriate. The details of potential cost savings in comparison to NGT's projections, excluding any alterations to NGT's transmission losses assumptions, are outlined in Table 6.2 below.

Table 6.2 – Potential cost savings in comparison to NGT's projections (money of the day)

Cost reductions vs NGT projections	Low	High
NGT's 2005/06 forecast	£543.2 million	£543.2 million
2004/05 outturn over-forecast	-£34.3 million	-£24.1 million
CAP047 costs	-£11.8 million	-£7.4 million
Within Scotland constraints	-£8.5 million	-£8.5 million
Cheviot constraints	-£18.5 million	-£18.5 million
Supplemental standing reserve	-£2.3 million	-£2.3 million
Amended target	**£467.8 million**	**£482.4 million**

6.31. In the context of a net transmission losses scheme, NGT's assumed TLA of £122.5 million would fall away with the result that this £467.8 million and £482.4 million range would be reduced be from £345.3 million to £359.9 million.

inflation indexation at 1.5 per cent.

6.32. On the basis of the above analysis and in recognition of the potential uncertainty surrounding the level of SO costs under BETTA, Ofgem is proposing a range of incentive scheme options with differing risk and reward profiles. The proposed targets within these options are set out in Table 6.3 below.

Table 6.3 – Proposed target values (money of the day)

Proposed value	Option 1	Option 2	Option 3
Target	£480 million	£500 million	£515 million

6.33. The target value in Option 1 sits towards the upper end of the target range outlined above, reflecting the uncertainty associated with these cost savings at this stage. The remaining two options have targets located between the target range identified above and NGC's mean forecast of £543.2 million. Ofgem considers that the target range presented above is appropriate given the need to balance the desire to provide a challenging target which both reflects NGC's experience as SO in E&W and accommodates any uncertainty associated with GB balancing costs in the first incentive period post-BETTA go-live.

6.34. Table 6.4 below displays the target values under a net losses scheme excluding the £122.5 million TLA allowance included within NGT's projections.

Table 6.4 – Proposed target values with a net losses incentive (money of the day)

Proposed value	Option 1	Option 2	Option 3
Target	£357.5 million	£377.5 million	£392.5 million

Sharing factors, cap and floor

6.35. For each of the proposed target values outlined above, Ofgem is proposing specific cap and floor values and sharing factors such that there is a range of challenging incentive scheme options with differing risk and reward profiles. Ofgem's proposed cap and floor values and sharing factors are outlined in Table 6.5.

Table 6.5 – Proposed sharing factors, cap and floor values (money of the day)

Proposed value	Option 1	Option 2	Option 3
Upside sharing factor	60%	40%	25%

Proposed value	Option 1	Option 2	Option 3
Downside sharing factor	15%	20%	25%
Cap	£50 million	£40 million	£25 million
Floor	-£10 million	-£20 million	-£25 million

6.36. In principle, Ofgem continues to consider that there should be symmetry between the sharing factors and between the cap and floor values, as this represents an appropriate balance between the interests of customers and NGC. However, in light of potential uncertainty concerning GB balancing costs in the initial period post-BETTA go-live period, NGT has outlined projected cost increases to reflect the risk created this uncertainty. As outlined above, Ofgem considers that the proposed cost increases may overstate this uncertainty and associated risk. In light of this, Ofgem has developed a suite of proposals which provide differing but appropriate balances of risk and reward for NGC. The intention is that NGT can choose from the menu the option that it considers to offer the most appropriate balance of risk and reward.

6.37. Therefore, consistent with approach adopted for the NETA go-live SO incentive scheme, in these Initial Proposals Ofgem has developed several incentive scheme options with differing levels of risk and reward. The options presented range from a high risk and high reward scheme through to a low risk and low reward scheme.

6.38. Option 1, which has the most challenging proposed target value, provides the potential for an attractive upside reward up to £50 million with a sharing factor of 60 per cent. The downside risk associated with this option is limited to a maximum of -£10 million with a sharing factor of 15 per cent, again in order to reflect that this option has the most challenging target.

6.39. Option 2, which proposes a higher target value than Option 1, also proposes asymmetry between cap and floor values and between sharing factors. However, the potential upside reward is lower at a maximum of £40 million with a sharing factor of 40 per cent, and the potential downside exposure is greater at a maximum of -£20 million with a sharing factor of 20 per cent.

6.40. Option 3, which has the highest target value, retains symmetrical cap and floor values and symmetrical sharing factors, such that potential upside reward and potential downside exposure are equivalent at £25 million and -£25 million respectively with sharing factors of 25 per cent.

6.41. In addition, Ofgem continues to consider that, in order to ensure consistency between NGC's internal and external SO incentive schemes, both schemes should have the same sharing factors. Ofgem considers that setting the same sharing factors for the internal and external SO incentives ensures that NGC's interests are aligned with those of customers by giving NGC incentives to reduce the total costs of system operation rather than arbitraging its position between the different incentive schemes. Therefore, Ofgem proposes that the internal and external sharing factors should continue to be aligned.

Incentive scheme options – summary

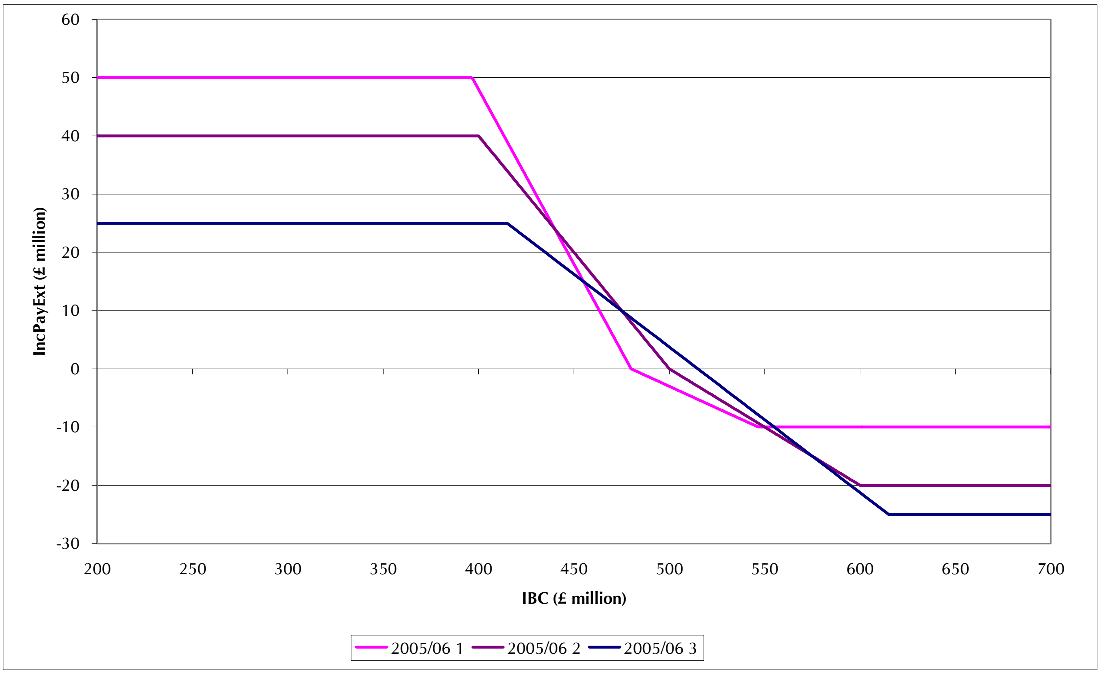
6.42. Table 6.6 below details the incentive scheme options outlined above, including gross treatment of transmission losses.

Table 6.6 – Incentive scheme options (money of the day)

Proposed value	Option 1	Option 2	Option 3
Target	£480 million	£500 million	£515 million
Upside sharing factor	60%	40%	25%
Downside sharing factor	15%	20%	25%
Cap	£50 million	£40 million	£25 million
Floor	-£10 million	-£20 million	-£25 million

6.43. Figure 6.1 below displays these options graphically.

Figure 6.1 – Incentive scheme options (money of the day)



6.44. Table 6.7 below details the incentive scheme options outlined above, including net treatment of transmission losses.

Table 6.7 – Incentive scheme options with a net losses incentive (money of the day)

Proposed value	Option 1	Option 2	Option 3
Target	£357.5 million	£377.5 million	£392.5 million
Upside sharing factor	60%	40%	25%
Downside sharing factor	15%	20%	25%
Cap	£50 million	£40 million	£25 million
Floor	-£10 million	-£20 million	-£25 million

Views invited

6.45. Ofgem welcomes views on the following:

- its initial proposal that the drafting describing the calculation of NIA will be reviewed to reflect the merger of UKPX and APX;
- its initial proposal that the NIRP price adjuster parameters will not be reviewed at this stage;

- its initial proposal that the transmission losses element of the incentive scheme will apply consistently across GB;
- its initial proposal that the GB transmission losses target should be set at 4.6TWh;
- its initial proposal to base TLRP on prevailing forward prices for the annual package for 2004/05;
- whether a net losses scheme is more appropriate than a gross losses scheme;
- the potential cost savings identified versus NGT's projected target;
- its proposed target values;
- its proposed cap and floor values and sharing factors; and
- its proposed incentive scheme options.

Timing of BETTA go-live

Ofgem's Initial Proposals

6.46. Ofgem notes that there was broadly equal support for the two options presented in the Initial Consultation as contingency mechanisms in the event that BETTA go-live is not implemented on 1 April 2005 as anticipated. Ofgem notes that NGT expressed a preference for Option 1, which involves rolling over the existing E&W scheme until the delayed BETTA go-live date is the most appropriate. Part of the basis for NGT's preference is that it is developing its forecast from April 2005 on the basis of GB costs as a whole, rather than for E&W and Scotland separately, as would be required under Option 2. In the absence of any clear consensus amongst respondents in relation to the options presented and in light of the points raised by NGT, Ofgem is proposing to proceed on the basis of Option 1, as this is a more practical approach given the circumstances.

6.47. Option 1 requires profiling of:

- the annual target, cap and floor values parameters in the rolled over E&W SO incentive scheme to derive an appropriate value for the period over which it applies ahead of actual BETTA go-live; and

- the annual target, cap and floor values parameters in the GB SO incentive scheme to derive an appropriate value for the period over which it applies after actual BETTA go-live.

6.48. Therefore, an appropriate profiling factor needs to be developed. One option which was suggested in the Initial Consultation was to use a profiling factor similar to that used in the initial incentive scheme under NETA in order to accommodate a scheme which was more or less than one year in duration. This profiling factor (NPF) was as follows:

$$NPF = \frac{ND}{365}$$

6.49. Where:

- ND was given by the number of days, between and including the day on which NETA go-live occurred, up to and including 31 March 2002.

6.50. A similar simplistic profiling factor could be applied in this case, with ND being based on the number of days, between and including the day on which BETTA go-live occurred, up to and including 31 March 2006.

6.51. A slightly more complex variant could be developed which, to the extent that IBC exhibits seasonality, attaches a greater weight to winter days than summer days. If, for example, 45 per cent of IBC is incurred in the summer period (1 April to 30 September inclusive) and 55 per cent of IBC is incurred in the winter period (1 October to following 31 March inclusive), weightings could be developed as follows:

$$NPF = \frac{(NDS * PFS) + (NDW * PFW)}{365}$$

- NDS is given by the number of days in the summer period, between and including the day on which NETA go-live occurred, up to and including 30 September 2005;

- PFS is the summer period profiling factor which is set at 0.9[61];

- NDS is given by the number of days in the winter period, between and including 1 October 2005, up to and including 31 March 2006; and

- PFW is the winter period profiling factor which is set at 1.1[62].

6.52. Ofgem considers that these profiling approaches are useful for consideration within this context.

Views invited

6.53. Ofgem welcomes views on the following:

- its initial proposal that, in the event that BETTA go-live is delayed beyond 1 April 2005, that a profiled version of the existing E&W SO incentive scheme should apply until BETTA go-live, at which point a profiled version of the GB SO incentive scheme intended to apply from 1 April 2005 will automatically apply;

- the appropriateness and relative merits of the profiling methods suggested above; and

- whether there are any other appropriate profiling methods which could be considered for this purpose.

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[61] 0.9 is derived as follows: ((0.45*365)/183), where 0.45 is the proportion of IBC incurred in the summer period, 365 is the number of days in the year and 183 is the number of days in the summer period.
[62] 1.1 is derived as follows: ((0.55*365)/182), where 0.55 is the proportion of IBC incurred in the winter period, 365 is the number of days in the year and 182 is the number of days in the winter period.

BSC Modification Proposals and CUSC Amendment Proposals

Ofgem's Initial Proposals

6.54. Ofgem continues to consider that the IAE provisions[63] should not be available for BSC Modification Proposals and CUSC Amendment Proposals which have been considered during the development of the incentive arrangements. Ofgem proposes to specify as part of its Final Proposals a list of BSC Modification Proposals and CUSC Amendment Proposals for which the IAE provisions will not apply. This measure in no way prejudices any decision of the Authority in respect of the Modification Proposals/Amendment Proposals.

6.55. CUSC Amendment Proposals CAP047[64] and CAP048[65] were explicitly excluded from the treatment outlined above during the development of the existing SO incentive scheme. These Initial Proposals include an allowance for CAP047, as outlined above. However, NGT has made no allowance for CAP048 in its projections and as such it is not reflected in these Initial Proposals. The treatment of these Amendment Proposals will continue to be considered as the incentive scheme to apply from April 2005 is developed.

Views invited

6.56. Ofgem welcomes views on the following:

- its initial proposal that the IAE provisions should not be available for a list of BSC Modification Proposals and CUSC Amendment Proposals to be specified in the Final Proposals.

[63] In November 2004, Ofgem initiated a statutory licence consultation in relation to the IAE provisions in both NGC's transmission licence and Transco's gas transporter licence, which proposed changes to the provisions intended to improve the transparency of the IAE process. The relevant document can be found at: http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/9371_262_IAE.pdf. Views on the proposed revisions are invited by 23 December 2004.
[64] CUSC Amendment Proposal CAP047: "Introduction of a competitive process for the provision of Mandatory Frequency Response".
[65] CUSC Amendment Proposal CAP048: "Firm Access and Temporary Physical Disconnection".

Information concerning NGC's role as SO

6.57. Ofgem notes that information relating to NGC's performance in its role as SO is currently provided to market participants via a number of means including the following:

- **NGC's operational forums:** NGC holds regular industry forums at which it provides data, detailed explanations of balancing actions and answers to questions raised by market participants. Until recently, NGC held three Operational forums per year. Interim Operational Forums have now been added into the timetable, with the result that NGC holds six Operational Forums per year (three full forums and three interim forums).

- **Balancing Principles Statement:** The BPS is intended to help market participants understand actions NGC may take to achieve the efficient, economic and co-ordinated operation of the transmission system. It defines the broad principles and criteria by which NGC will determine, at different times and in different circumstances, which balancing services it will use to assist in the operation of the transmission system. The BPS is subject to annual review and industry consultation.

  Standard condition C16 of the transmission licence requires NGC to prepare and publish annually an audited report on the manner in which, and the extent to which, it has complied with the BPS in the previous 12 months. This is published on NGC's website[66] for interested parties to view.

- **Procurement Guidelines:** The PGs detail the types of balancing services that NGC may be interested in purchasing, together with the mechanisms envisaged for purchasing such balancing services. The PGs are subject to annual review and industry consultation.

  Standard condition C16 of the transmission licence requires NGC to prepare and publish annually a report which provides information in

[66] www.nationalgrid.com/uk/indinfo

respect of the relevant Balancing Services that NGC has procured in the defined reporting period. This is also published on NGC's website for interested parties to view. Market participants have the opportunity to submit comments and suggestions to the Authority on the scope and content of the PGs reports.

Table 3 within Part E of the PGs outlines NGC's approach to providing information relating to its procurement of balancing services in order to provide market participants and other interested parties with sufficient information without compromising the commercial position of any contracting party. A number of regular reporting strands are provided in NGC's website in accordance with this requirement.

- **Monthly Balancing Service Summary:** In addition to the reporting required under standard condition C16, NGC has, following the outcome of its recent Transparency Review, undertaken publish a Monthly Balancing Service Summary to increase the visibility of the balancing actions taken. The Monthly Balancing Services Summary provides information on the procurement of Balancing Services in twelve separate monthly publications. This is also published on NGC's website for interested parties to view.

6.58. Ofgem currently considers that the mechanisms outlined above are useful in providing market participants and interested parties with information in relation to NGC's activities and its performance as SO. Consequently, Ofgem is not currently raising any issues in relation to the level of information provision. The purpose of this section is instead to invite any feedback that market participants may wish to make in relation to the level of information provision concerning NGC's activities and its performance as SO.

Summary

6.59. This chapter has outlined Ofgem's Initial Proposals in respect of the SO incentive scheme to apply from 1 April 2005. A summary of these Initial Proposals is provided below:

- the scope of the SO incentive scheme should cover all electricity and system balancing costs within the control of the SO;
- the form of the SO incentive scheme should remain as a sliding scale incentive;
- the duration of the SO incentive scheme should be one year;
- in the event of a delay in BETTA go-live beyond 1 April 2005, the existing E&W SO incentive scheme will be rolled over, having been profiled accordingly until BETTA go-live occurs. At BETTA go-live, the GB SO incentive scheme which is currently being developed will automatically begin, having been profiled accordingly;
- that it the methodology used to derive NIRP will be revised to reflect that there is now only one data provider;
- that it may be appropriate for the transmission losses element of the incentive scheme to be net rather than gross;
- that specified Modification Proposals/Amendment Proposals should be excluded from treatment under the IAE provisions as part of the SO incentive scheme; and
- that the proposed incentive scheme options at this stage are as outlined in Table 6.8 in the context of a gross losses incentive.

Table 6.8 – Incentive scheme options (money of the day)

Proposed value	Option 1	Option 2	Option 3
Target	£480 million	£500 million	£515 million
Upside sharing factor	60%	40%	25%
Downside sharing factor	15%	20%	25%
Cap	£50 million	£40 million	£25 million
Floor	-£10 million	-£20 million	-£25 million

7. Way forward

Summary of views invited

7.1. Ofgem invites view on any of the issues raised in this document. Responses should be submitted by 21 January 2004. In particular, Ofgem invites views on:

Scope of the GB SO incentive scheme to apply from 1 April 2005

- its initial proposal that the scope of the GB SO incentive scheme should be consistent with the scope of the existing E&W SO incentive scheme.

Form of the GB SO incentive scheme to apply from 1 April 2005

- its initial proposal that a sliding scale incentive scheme should be developed;
- its initial proposal that a single GB wide SO incentive scheme should be developed;
- its initial proposal that a deadband target range should not be considered; and
- its initial proposal to allow asymmetric cap, floor and sharing factors in order to accommodate any perceived uncertainty in relation to GB SO costs.

Duration of the GB SO incentive scheme to apply from 1 April 2005

- its initial proposal that the duration of the GB SO incentive scheme to apply from 1 April 2005 should be one year in duration.

Incentive scheme parameters

- its initial proposal that the drafting describing the calculation of NIA will be reviewed to reflect the merger of UKPX and APX;
- its initial proposal that the NIRP price adjuster parameters will not be reviewed at this stage;
- its initial proposal that the transmission losses element of the incentive scheme will apply consistently across GB;
- its initial proposal that the GB transmission losses target should be set at 4.6TWh;
- its initial proposal to base TLRP on prevailing forward prices for the annual package for 2004/05;
- whether a net transmission losses scheme is more appropriate than a gross losses scheme;
- the potential cost savings identified versus NGT's projected target;
- its proposed target values;
- its proposed cap and floor values and sharing factors; and
- its proposed incentive scheme options.

Timing of BETTA go-live

- its initial proposal that, in the event that BETTA go-live is delayed beyond 1 April 2005, a profiled version of the existing E&W SO incentive scheme should apply until BETTA go-live, at which point a profiled version of the GB SO incentive scheme intended to apply from 1 April 2005 will automatically apply;
- the appropriateness and relative merits of the profiling methods suggested above; and

- whether there are any other appropriate profiling methods which could be considered for this purpose.

BSC modification proposals and CUSC amendment proposals

- its initial proposal that the IAE provisions should not be available for a list of BSC Modification Proposals and CUSC Amendment Proposals to be specified in the Final Proposals.

Information concerning NGC's role as SO

- whether the current level of information provision concerning NGC's activities as SO is appropriate.

Next steps

7.2. Following consideration of respondents' views to this Initial Consultation, which are requested by 21 January 2005, Ofgem expects to publish its next document in relation to the SO incentive scheme from 1 April 2005 in February 2005.

Appendix 1 Historic incentive scheme structure

Details of the external SO incentive schemes under NETA

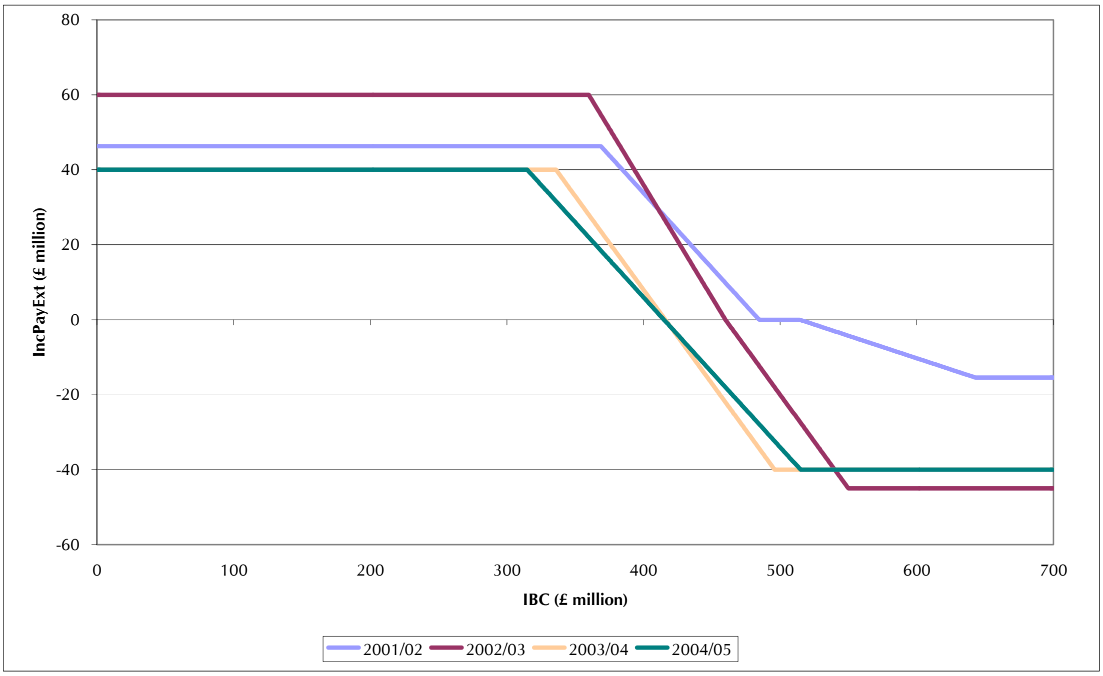
1.1 There have been four external SO incentive schemes under NETA. The initial incentive scheme ran from 27 March 2001 (the go-live date for NETA) to 31 March 2002, the second ran from 1 April 2002 to 31 March 2003 and the third from 1 April 2003 until 31 March 2004. The current SO incentive scheme commenced on 1 April 2004 and is due to expire on 31 March 2005. The parameters of all four external cost incentive schemes to date are outlined in Table A1.1. The structure of all four external cost incentive schemes to date is shown graphically in Figure A1.1.

Table A1.1 – SO external cost incentive parameters since NETA go-live (money of the day)

Parameter	2001/02 scheme[67]	2002/03 scheme	2003/04 scheme	2004/05 scheme
Target	£484.6 million to £514.4 million	£460 million	£416 million	£415 million
Upside sharing factor[68]	40%	60%	50%	40%
Downside sharing factor[69]	12%	50%	50%	40%
Cap	£46.3 million	£60 million	£40 million	£40 million
Floor	-£15.4 million	-£45 million	-£40 million	-£40 million

[67] The figures presented in relation to the initial incentive scheme represent the finalised parameters for the scheme following adjustments to reflect that the scheme was 370 days in duration, not 365 days, and inflation indexation at 1.5 per cent.
[68] The upside sharing factor is the proportion of any cost savings which NGC keeps as an incentive payment.
[69] The downside sharing factor is the proportion of any cost overruns to which NGC is exposed.

Figure A1.1 – Incentive structure under the SO external cost schemes (money of the day)



1.2 The lower target for the current incentive scheme reflects NGC's improved understanding of operating the system under NETA gained during the first three years of NETA. The current incentive scheme target continues to place commercial incentives on NGC to manage its system operation costs on behalf of customers.

1.3 NGC's SO incentive scheme payment or receipt is determined by the level of its Incentivised Balancing Costs (IBC) at the end of the incentive period. IBC are calculated from a number of different components[70]:

- the cost of bids and offers in the Balancing Mechanism accepted in the relevant period less the total non-delivery charge for that period. This is referred to as Daily System Operator Balancing Mechanism Cashflow (CSOBM);

- the costs of contracts for the availability or use of balancing services, excluding costs covered by CSOBM (but including charges made by the SO for the provision of balancing services to itself), i.e. this component

[70] In addition to the terms outlined below, Ofgem is expecting to consult shortly on the inclusion of a further term (the IP_t term linked to CUSC Amendment Proposal CAP048: "Firm Access and Temporary Physical

consists of the costs of balancing services not procured through the Balancing Mechanism. This is referred to as Balancing Services Contract Costs (BSCC);

- the volume of transmission losses multiplied by the Transmission Losses Reference Price (TLRP) for each Settlement Period, summed across all Settlement Periods. This is referred to as the Transmission Losses Adjustment (TLA);

- the system imbalance volume multiplied by the Net Imbalance Volume Reference Price (NIRP) for each Settlement Period, summed across all Settlement Periods. This factor, the Net Imbalance Adjustment (NIA), is deducted from CSOBM to reflect the fact that NGC has little control over the extent to which participants choose not to balance their positions;

- the revenue from the provision of balancing services to others (OM) during relevant incentive period; and

- the amount of any allowed income adjustment (RT) during the relevant incentive period.

Disconnection").

Appendix 2 Incentivised Balancing Cost component breakdown

Balancing Mechanism Costs (CSOBM)

Licence definition

2.1 Under NGC's Transmission Licence $CSOBM_t$ is defined as the cost to the licensee of bids and offers in the Balancing Mechanism accepted by the licensee in relevant period t[71] less the total non-delivery charge for that period. $CSOBM_t$ is the sum across the relevant period of the values of $CSOBM_j$ (being the Daily System Operator Balancing Mechanism Cashflow as defined in Table X-2 of Section X of the BSC in force immediately prior to 1 April 2001).

Performance to date[72]

2.2 $CSOBM_t$ over the period from 1 April 2003 until 31 March 2004 totalled £74.45 million. Cumulative daily CSOBM from 1 April 2004 until 31 October 2004 was £48.79 million. Figure A2.1 shows daily CSOBM, monthly average CSOBM and a four-week rolling average of CSOBM for the period between 1 April 2003 and 31 October 2004.

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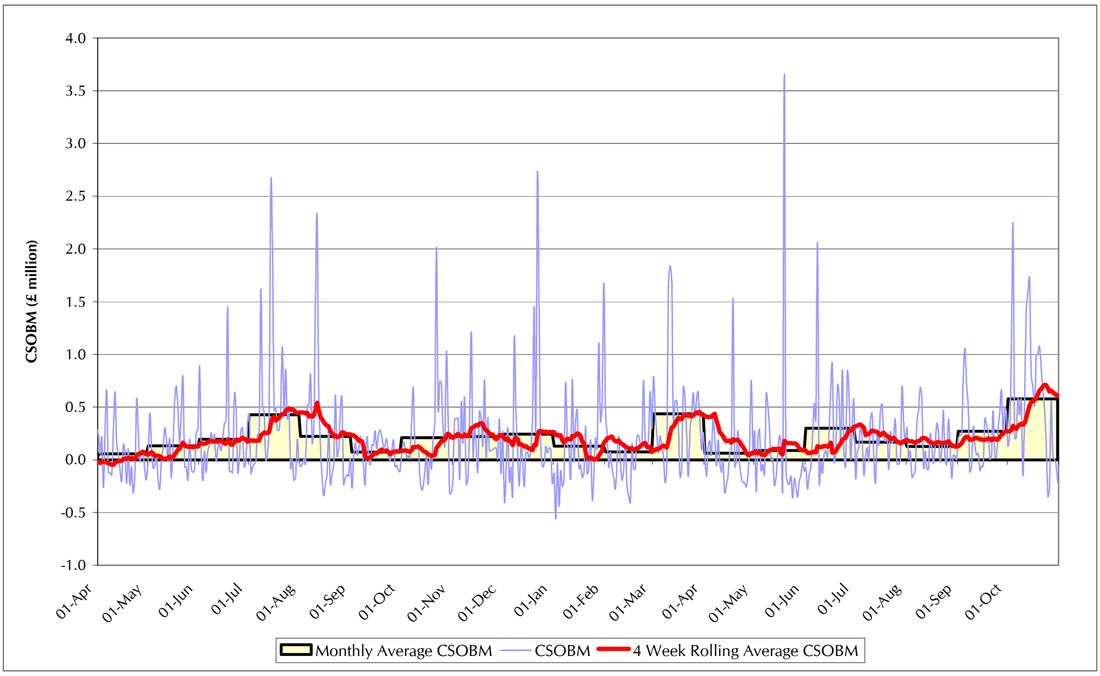
[71] The transmission licence defines "relevant period t" as that period for the purposes of which any calculation falls to be made commencing on go-live and ending on 31 March 2002 and thereafter shall have the same meaning as "relevant year t" where "relevant year t" means that relevant year for the purposes of which any calculation falls to be made.
[72] Similar analysis and commentary for the period prior to 1 April 2002 can be found in 'NGC system operator incentive scheme from 1 April 2003 – 31 March 2004, final proposals and statutory licence conditions', March 2003, Ofgem, at the following address: http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/2545_16so_incentives.pdf

Figure A2.1 – CSOBM from 1 April 2003 until 31 October 2004 (money of the day)



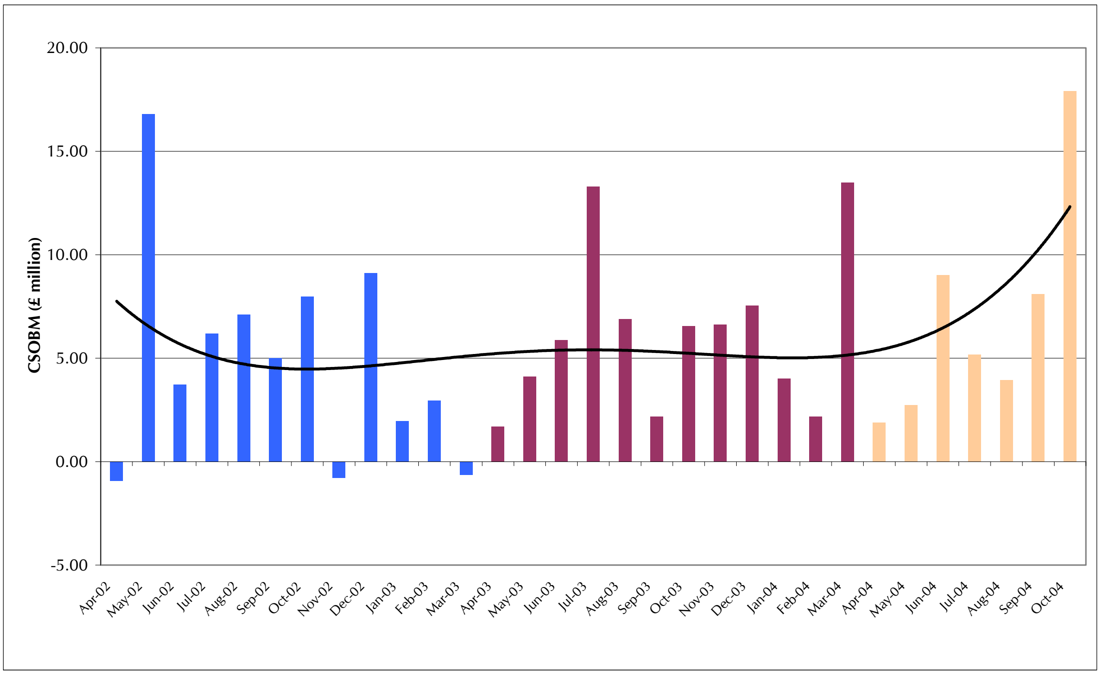
2.3 During the first year of NETA, CSOBM fell consistently in response to a number of factors, amongst which were NGC's and market participants' growing experience of the new arrangements. CSOBM was much more volatile during the second year of NETA, with the first two months of the financial year totalling -£0.93 million and £16.80 million for April 2002 and May 2002 respectively. Further CSOBM spikes occurred in July 2003 and March 2004, reaching the fourth and third highest monthly total since NETA go-live at £13.28 million and £13.50 million respectively.

2.4 Financial year 2003/04 has seen monthly CSOBM remain positive, mainly as a consequence of the system becoming closer to balance, and the cashflows associated with bid volumes reduced. The seven months from April 2004 show a rapid increase in CSOBM, most notably in October 2004, where costs rose to the highest level since April 2001, at £17.91 million. October can be a difficult month to balance the system due to rising demand without an offsetting increase in plant returning to the system from maintenance outages. More detailed statistics concerning CSOBM can be found in Table A2.1 and Figure A2.2.

Table A2.1 – Monthly CSOBM statistics (£ million, money of the day)[73]

Month	Sum	Average	Min	Max	Standard deviation
Apr-03	1.70	0.06	-0.32	0.65	0.26
May-03	4.12	0.13	-0.27	0.78	0.27
Jun-03	5.87	0.20	-0.20	1.45	0.34
Jul-03	13.28	0.43	-0.19	2.62	0.64
Aug-03	6.90	0.22	-0.34	2.31	0.56
Sep-03	2.18	0.07	-0.27	0.28	0.14
Oct-03	6.56	0.21	-0.32	2.02	0.47
Nov-03	6.61	0.22	-0.23	1.21	0.32
Dec-03	7.54	0.24	-0.40	2.72	0.64
Jan-04	4.01	0.13	-0.56	1.67	0.47
Feb-04	2.18	0.08	-0.40	0.75	0.27
Mar-04	13.50	0.44	-0.22	1.84	0.51
Apr-04	1.88	0.06	-0.31	1.53	0.35
May-04	2.73	0.09	-0.36	3.66	0.71
Jun-04	9.02	0.30	-0.28	2.06	0.48
Jul-04	5.19	0.17	-0.22	0.69	0.21
Aug-04	3.94	0.13	-0.18	0.69	0.23
Sep-04	8.12	0.27	-0.11	1.06	0.29
Oct-04	17.91	0.58	-0.35	2.23	0.61

Figure A2.2 – Monthly CSOBM statistics including trendline (money of the day)



[73] For tables A2.1 to A2.4, each IBC component shows total cashflow for the month, average daily cashflow and minimum, maximum and standard deviation figures over the course of each month.

Balancing Services Contract Costs (BSCC)

Licence definition

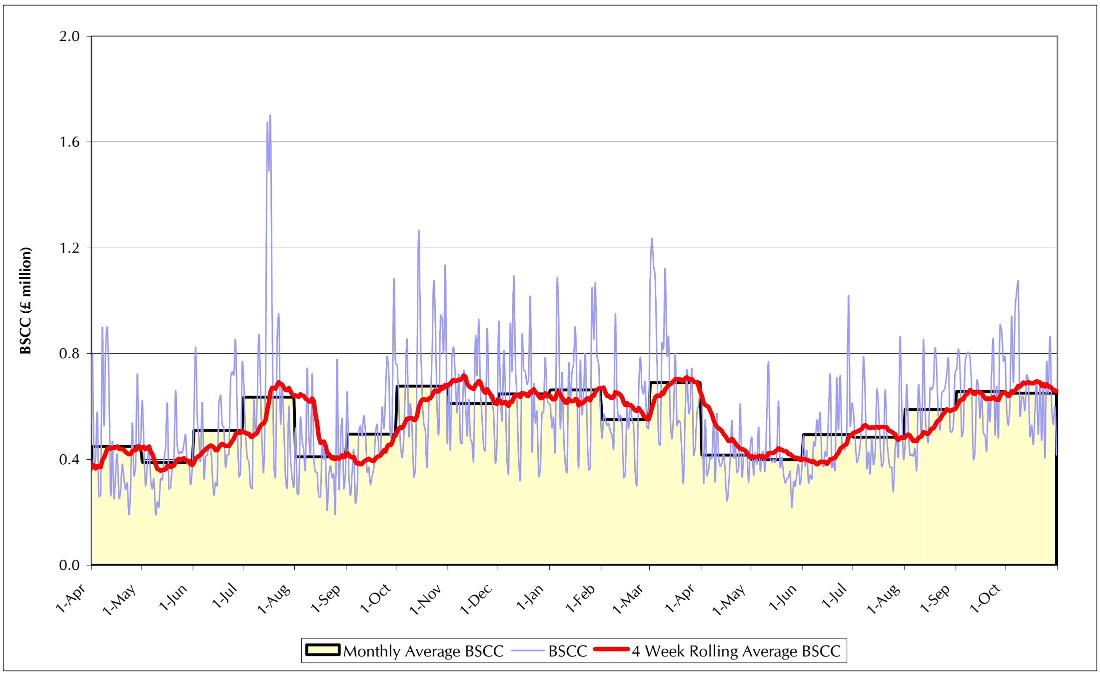
2.5 Under NGC's Transmission Licence, $BSCC_t$ is defined as the costs to the licensee of contracts for the availability or use of balancing services during the relevant period t, excluding costs within $CSOBM_t$ but including charges made by the licensee for the provision of balancing services to itself in the relevant period t.

2.6 $BSCC_t$ are the costs of the payments that NGC makes under contract to the providers of balancing services excluding any costs paid through the Balancing Mechanism. This includes costs associated with the procurement of energy, reserve, frequency response, some transmission constraints, black start and reactive power. All these costs are bundled together as BSCC for the purposes of the IBC calculation.

Performance to date

2.7 $BSCC_t$ over the period from 1 April 2003 to 31 March 2004 totalled £205.51 million. Cumulative daily BSCC from 1 April 2004 until 31 October 2004 was £112.82 million. Figure A2.3 shows daily BSCC, monthly average BSCC and a four-week rolling average of BSCC for the period between 1 April 2003 and 31 October 2004.

Figure A2.3 – BSCC from 1 April 2003 until 31 October 2004 (money of the day)



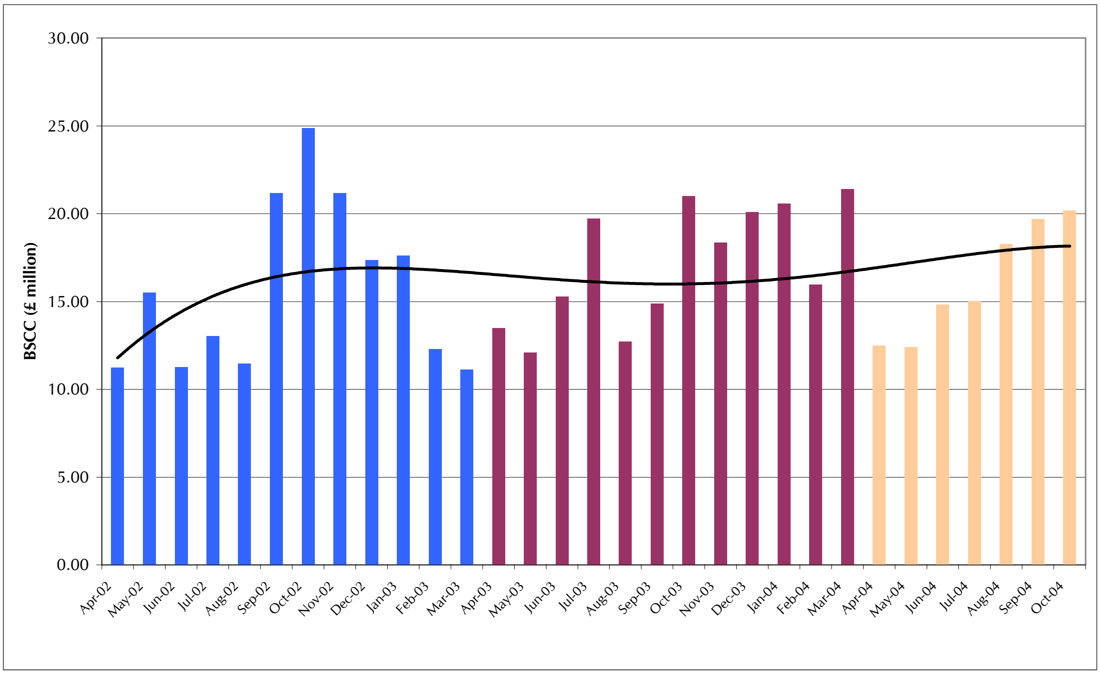
2.8 As was the case for the year from NETA go-live, total monthly BSCC fluctuated over the first half of the financial year 2002/2003. Between August 2002 and September 2002, total monthly BSCC almost doubled from £11.46 million to £21.17 million. Monthly total BSCC climbed to a peak of £24.88 million in October 2002. BSCC remained high over the winter period before slowly falling to £11.12 million in March 2003. The second half of financial year 2003/04 saw BSCC remaining in a high range between £15.96 million (February 2004) and £21.39 million (March 2004). BSCC dramatically fell back in April 2004, with the lowest monthly sum for a year at £12.48 million. Beyond April 2004, BSCC rose in each consecutive month, to reach one of the highest levels under NETA, in October 2004 at £20.17 million. More detailed statistics concerning BSCC are presented in Table A2.2 and Figure A2.4.

Table A2.2 – Monthly BSCC statistics (£ million, money of the day)

Month	Sum	Average	Min	Max	Standard deviation
Apr-03	13.50	0.45	0.19	0.90	0.20
May-03	12.07	0.39	0.19	0.66	0.11
Jun-03	15.30	0.51	0.27	0.85	0.17
Jul-03	19.71	0.64	0.29	1.68	0.38
Aug-03	12.72	0.41	0.21	0.78	0.15
Sep-03	14.87	0.50	0.23	1.08	0.18
Oct-03	21.01	0.68	0.33	1.27	0.24

Month	Sum	Average	Min	Max	Standard deviation
Nov-03	18.34	0.61	0.39	0.93	0.15
Dec-03	20.09	0.65	0.33	1.09	0.20
Jan-04	20.56	0.66	0.35	1.07	0.21
Feb-04	15.96	0.55	0.31	0.95	0.13
Mar-04	21.39	0.69	0.32	1.24	0.24
Apr-04	12.48	0.42	0.24	0.65	0.10
May-04	12.39	0.40	0.22	0.77	0.11
Jun-04	14.81	0.49	0.31	1.02	0.15
Jul-04	15.00	0.48	0.28	0.86	0.13
Aug-04	18.26	0.59	0.37	0.85	0.13
Sep-04	19.70	0.66	0.40	0.91	0.15
Oct-04	20.17	0.65	0.41	1.07	0.17

Figure A2.4 – Monthly BSCC statistics including trendline (money of the day)



Transmission Losses (TL) and Transmission Losses Reference Price (TLRP)

Licence definition

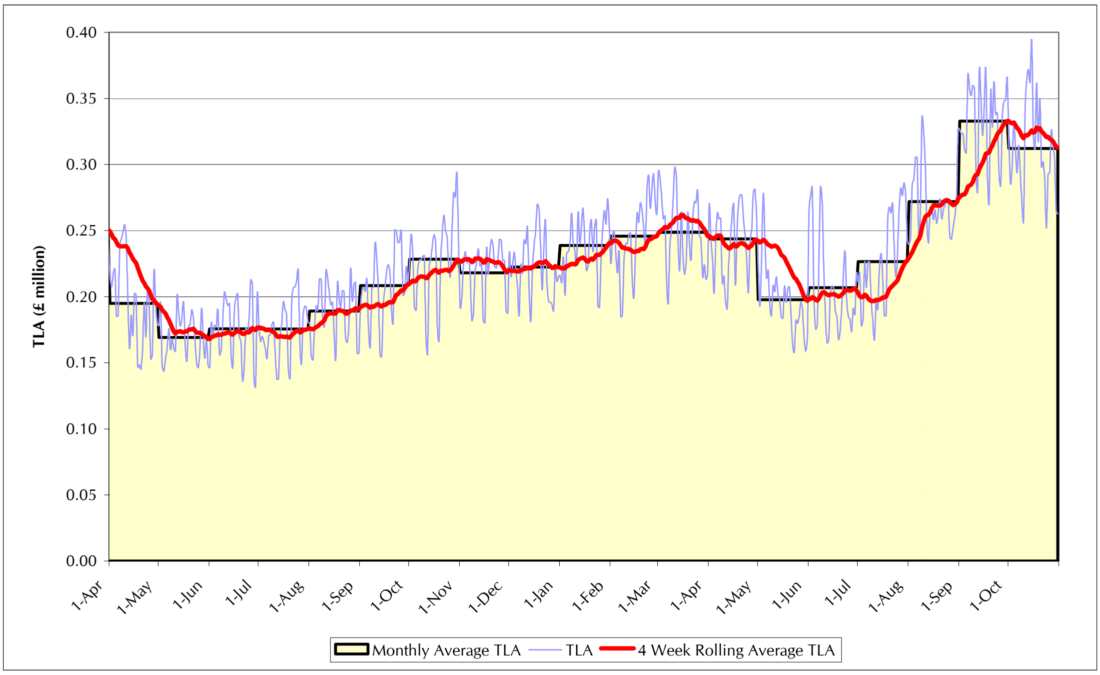
2.9 Under NGC's Transmission Licence, $\sum_{jt}(TL_j[TLRP_j])$, referred to as the Transmission Losses Adjustment (TLA), is defined as the volume of Transmission Losses (TL_j) multiplied by the Transmission Losses Reference Price ($TLRP_j$) for each Settlement Period, summed across all Settlement Periods in the relevant period t. It is the difference between the quantities of electricity delivered to the licensee's transmission system and the quantity taken from the licensee's transmission system during that Settlement Period, but excluding all generator transformer losses.

2.10 NGC has incentives to reduce the overall volume of losses and a reference price (TLRP) is required to allow a cost target to be included in IBC. $TLRP_j$ has the value specified for each Settlement Period set out in paragraph B3 of Part B of Schedule A of NGC's Transmission Licence. During the period from 27 March 2001 until 31 March 2002, TLRP was fixed at £20.30/MWh (after indexation). It was reduced to £18.50/MWh for the period from 1 April 2002 until 31 March 2003. For the period between 1 April 2003 and 31 March 2004, TLRP was again reduced to £17.00/MWh. TLRP was further revised for the incentive scheme period between 1 April 2004 and 31 March 2005 to £21.00/MWh.

Performance to date

2.11 Over the period from 1 April 2003 until 31 March 2004, TLA_t totalled £76.68 million. Cumulative daily TLA from 1 April 2004 until 31 October 2004 was £54.75 million. Figure A2.5 shows daily TLA, monthly average TLA and a four-week rolling average of TLA for the period between 1 April 2003 and 31 October 2004.

Figure A2.5 – TLA from 1 April 2003 until 31 October 2004 (money of the day)



2.12 Historically, TLA has been the least volatile of the IBC components because of the annually fixed nature of TLRP. Moreover, the value of TLA depends only on the volume of transmission losses in any given period. As the transmission losses volume is a function of the volume of electricity generated (or demanded), there is a clear correlation between seasonal demand patterns and the value of TLA.

2.13 The value of TLRP itself has been altered on an annual basis. As a result of alterations to TLRP, the value of TLA has changed slightly year-on-year. For the incentive scheme period 2002/03 the spread between maximum daily TLA and minimum daily TLA was £0.18 million, whilst for the 2003/04 incentive scheme this figure fell slightly to £0.17 million. For the earlier part of the current incentive scheme, TLA was much less volatile, with the range being around £0.13 million[74]. However, from August 2004, the range rose considerably. September 2004 and October 2004, account for the highest costs for TLA under NETA, although this is mainly the result of the higher value for TLRP, rather than an increase in the volume of transmission losses. More detailed statistics concerning TLA are presented in Table A2.3 and Figure A2.6.

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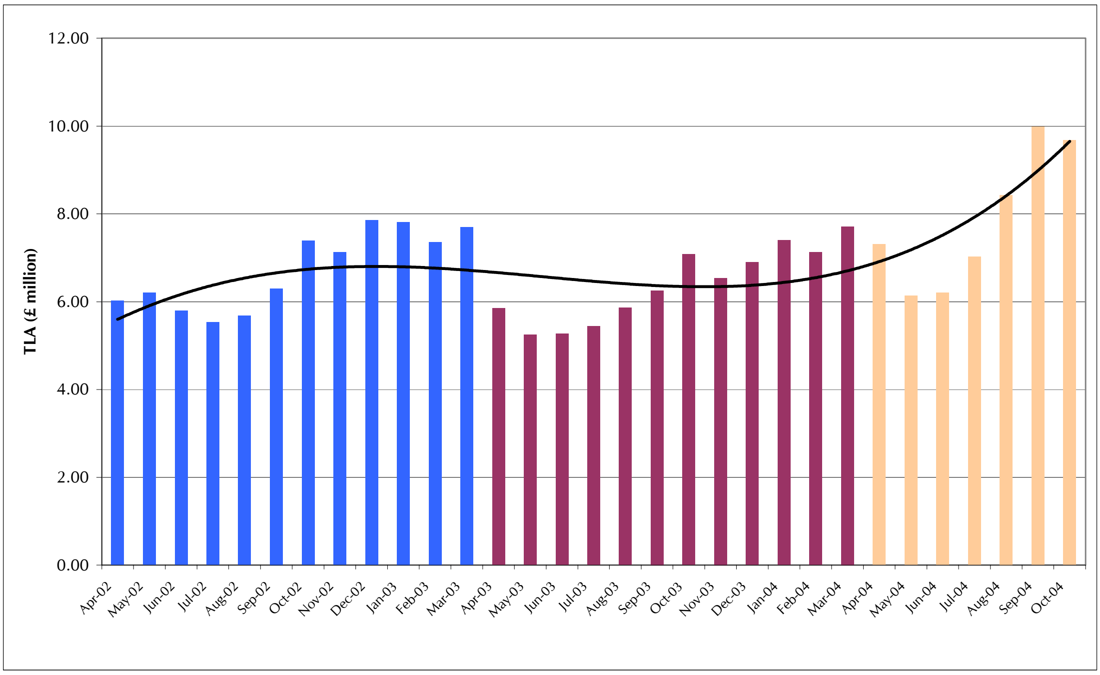
[74] Accounting for rounding.

Table A2.3 – Monthly TLA statistics (£ million, money of the day)

Month	Sum	Average	Min	Max	Standard deviation
Apr-03	5.85	0.19	0.15	0.25	0.03
May-03	5.25	0.17	0.14	0.20	0.02
Jun-03	5.27	0.18	0.13	0.21	0.02
Jul-03	5.44	0.18	0.14	0.22	0.02
Aug-03	5.86	0.19	0.15	0.22	0.02
Sep-03	6.25	0.21	0.15	0.25	0.03
Oct-03	7.08	0.23	0.16	0.29	0.03
Nov-03	6.54	0.22	0.18	0.24	0.02
Dec-03	6.90	0.22	0.18	0.27	0.02
Jan-04	7.40	0.24	0.19	0.27	0.02
Feb-04	7.13	0.25	0.19	0.29	0.03
Mar-04	7.71	0.25	0.20	0.30	0.03
Apr-04	7.31	0.24	0.19	0.28	0.03
May-04	6.13	0.20	0.16	0.28	0.03
Jun-04	6.20	0.21	0.17	0.28	0.04
Jul-04	7.02	0.23	0.17	0.29	0.04
Aug-04	8.43	0.27	0.24	0.34	0.03
Sep-04	9.98	0.33	0.27	0.37	0.03
Oct-04	9.67	0.31	0.25	0.39	0.04

Figure A2.6 – Monthly TLA statistics including trendline (money of the day)



Total Net Energy Imbalance Volume (TQEI) and the Net Imbalance Volume Reference Price (NIRP)

Licence definition

2.14 Under NGC's Transmission Licence, $\sum_{jt}(TQEI_j[NIRP_j])$, referred to as the Net Imbalance Adjustment (NIA), is defined as the Total Net Imbalance Volume[75] ($TQEI_j$), as defined in the BSC in force immediately prior to 1 April 2001, multiplied by the Net Imbalance Volume Reference Price ($NIRP_j$) for each Settlement Period, summed across all Settlement periods in the relevant period t.

2.15 $NIRP_j$ has the value specified for each Settlement Period set out in paragraph B4 of Part B of Schedule A of NGC's Transmission Licence. During the period from 27 March 2001 until 31 March 2002, $NIRP_j$ was based on imbalance prices using the definitions of System Buy Price (SBP) and System Sell Price (SSP) included in the version of the BSC in force immediately prior to 1 April 2001. Whether SBP or SSP applied was dependent upon TQEI. NIRP was set to be equal to SBP when the system was short, i.e. $TQEI<0$, SSP when the system was long, i.e. $TQEI>0$, and zero when the system was in balance.

2.16 The definition of NIRP was changed ahead of the 2002/03 incentive scheme. The first stage in deriving $NIRP_j$ is now to calculate the Single Price Net Imbalance Volume Reference Price for the settlement period ($SPNIRP_j$). This is a market based reference price calculated from a basket of power exchange prices (the United Kingdom Power Exchange (UKPX) and United Kingdom Automated Power Exchange (UK APX)). A variable price adjustment is then applied to $SPNIRP_j$ to give $NIRP_j$. When the system is long $SPNIRP_j$ is multiplied by 0.5 whereas when the system is short it is multiplied by 2.5.

Performance to date

2.17 NIA_t over the period from 1 April 2003 until 31 March 2004 totalled £0.42 million. Cumulative daily NIA from 1 April 2004 until 31 October 2004 was

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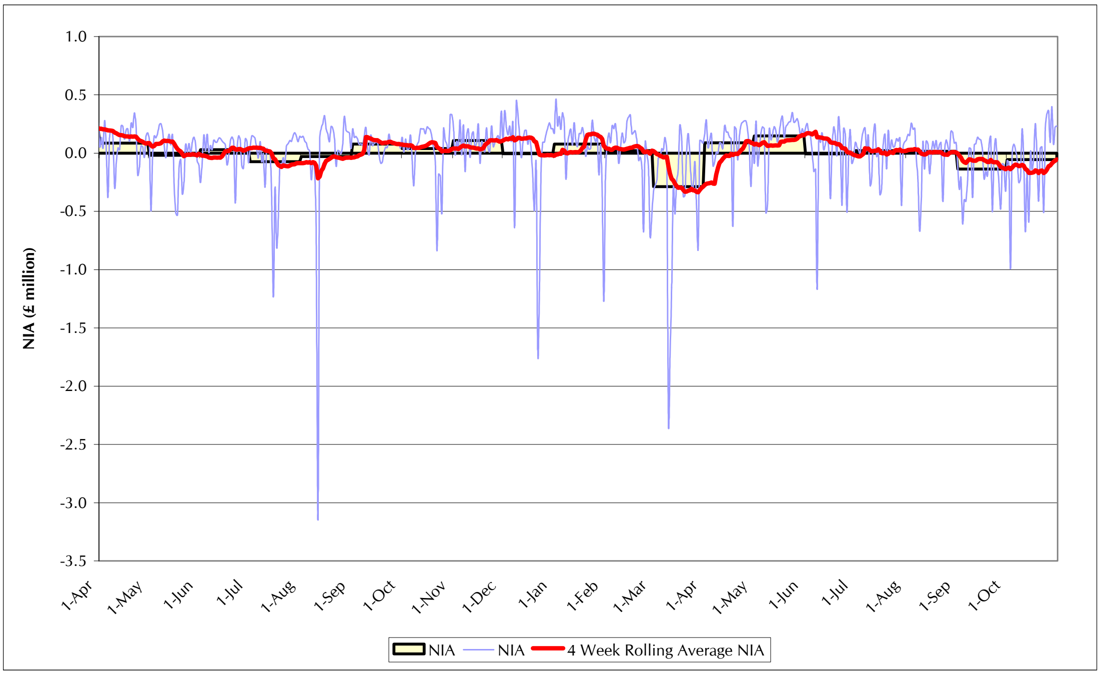
[75] The total net imbalance volume is the sum of all imbalance volumes over all energy accounts other than energy accounts held by the Transmission Company.

£2.31 million. Figure A2.7 shows daily NIA, monthly average NIA and a four-week rolling average of NIA for the period between 1 April 2003 and 31 October 2004.

Figure A2.7 – NIA from 1 April 2003 until 31 October 2004 (money of the day)



2.18 For the most part, NIA has historically been positive because the system has tended to be long. This means that the TQEI element of NIA has been positive and contributes to the magnitude of IBC. Over time, the tendency to be long has lessened, and fell substantially upon implementation of BSC Modification P78[76] on 11 March 2003.

2.19 For a number of months under each incentive scheme period, average monthly NIA has actually been negative. This does not necessarily mean that the system has been short as the value of NIRP is greater when the system is short than when it is long. However, the 2003/04 incentive scheme has demonstrated the effects of the system becoming closer to balance. Five of the twelve months show a negative value for NIA, whilst the net value itself for the period is slightly above zero. NIA in March 2004 reached the lowest point since NETA go-live at -£8.95 million, indicative of a number of tight days on the system. September

[76] Information concerning BSC Modification P78 "Revised definitions of system buy price and system sell price" can be found on ELEXON's website at http://www.elexon.co.uk.

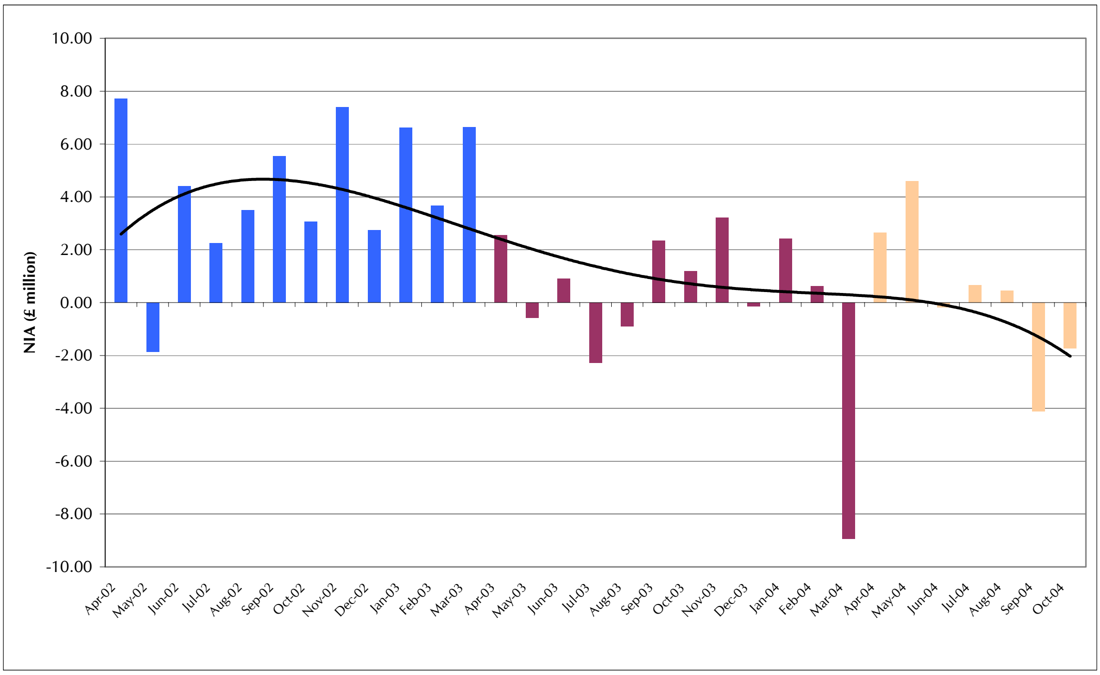
2004 and October 2004 were also reasonably tight days with high imbalance prices and forward prices, and as a result are negative values. The high negative NIA in these months coincide with high positive CSOBM and BSCC costs as it was necessary for NGC to contract for large volumes of balancing actions.

2.20 With this in mind, the system has shown negative NIA costs for 29 per cent of the days in financial year 2003/04 (106 days out of 366 days). For the current incentive scheme period this figure has risen to 34 per cent (72 days from 214 days). In comparison, from NETA go-live to 31 March 2003, this figure was just 15 per cent (110 days out of 735 days). More detailed statistics concerning NIA are presented in Table A2.4.

Table A2.4 – Monthly NIA statistics (£ million, money of the day)

Month	Sum	Average	Min	Max	Standard deviation
Apr-03	2.55	0.09	-0.38	0.34	0.17
May-03	-0.57	-0.02	-0.53	0.25	0.22
Jun-03	0.90	0.03	-0.43	0.16	0.13
Jul-03	-2.27	-0.07	-1.23	0.17	0.31
Aug-03	-0.90	-0.03	-3.14	0.32	0.61
Sep-03	2.35	0.08	-0.09	0.22	0.07
Oct-03	1.19	0.04	-0.84	0.33	0.24
Nov-03	3.21	0.11	-0.16	0.36	0.12
Dec-03	-0.14	0.00	-1.73	0.44	0.45
Jan-04	2.42	0.08	-1.27	0.46	0.30
Feb-04	0.63	0.02	-0.71	0.33	0.26
Mar-04	-8.95	-0.29	-2.30	0.24	0.55
Apr-04	2.64	0.09	-0.63	0.29	0.19
May-04	4.59	0.15	-0.51	0.35	0.19
Jun-04	-0.18	-0.01	-1.17	0.31	0.30
Jul-04	0.66	0.02	-0.45	0.25	0.17
Aug-04	0.45	0.01	-0.67	0.26	0.20
Sep-04	-4.12	-0.14	-0.61	0.14	0.22
Oct-04	-1.73	-0.06	-0.99	0.40	0.32

Figure A2.8 – Monthly NIA statistics including trendline (money of the day)



Other Allowed Income (RT) and Balancing Services provided to others (OM)

Licence definition

2.21 Under NGC's Transmission Licence, RT_t is defined as the amount of any allowed income adjustment, given by paragraph 12(b) of special condition AA5A, in respect of relevant period t.

2.22 NGC's Transmission Licence defines OM_t as the amount representing the revenue from the provision of balancing services to others during relevant period t, calculated in accordance with paragraph 7 of special condition AA5A.

Performance to date

2.23 From the introduction of NETA to date, OM has been zero, whilst RT has been non-zero for two events. RT can only be non-zero if Ofgem agrees to a change to the incentive scheme target as a result of an Income Adjusting Event (IAE). To date, NGC is the only party to have issued a notice to the Authority outlining costs or expenses incurred or saved which it considered to relate to an IAE, although it is open for any BSC Party to raise an IAE to the Authority. In March

2003, NGC gave notice to Ofgem that it considered an IAE had occurred during November 2002. The Authority approved the proposed IAE in June 2003 and RT was assigned a value of £5.34 million (and so reduced IBC by £5.34 million)[77]. Furthermore, in April 2004, NGC gave notice to Ofgem that it considered an IAE had occurred during November 2003. The Authority approved the proposed IAE in July 2004 and RT was assigned a value of £5.54 million (and so reduced IBC by £5.54 million)[78].

Contribution of components to IBC

2.24 In addition to examining the trends of the individual components of IBC, an examination of each component's relative contribution to IBC throughout the period is set out below. Tables A2.5 and A2.6 provide a breakdown of average monthly IBC component totals and their contributions to IBC.

Table A2.5 – Average monthly IBC component totals (£ million, money of the day)[79]

Period	CSOBM	BSCC	TLA	NIA	IBC
Go-Live to Oct-04	5.62	14.93	6.90	2.55	30.01
Go-Live to Mar-02	5.05	11.59	7.03	4.45	28.12
Apr-02 to Mar-03	4.88	15.67	6.73	4.31	31.58
Apr-03 to Mar-04	6.20	17.13	6.39	0.03	29.75
Apr-04 to Oct-04	6.97	16.12	7.82	0.33	31.24

Table A2.6 – Average monthly IBC components as proportion of IBC[80]

Period	CSOBM	BSCC	TLA	NIA
Go-Live to Oct-04	19%	50%	23%	9%
Go-Live to Mar-02	18%	41%	25%	16%
Apr-02 to Mar-03	15%	50%	21%	14%
Apr-03 to Mar-04	21%	58%	21%	0%
Apr-04 to Oct-04	22%	52%	25%	1%

2.25 Monthly total CSOBM averaged £4.88 million for the period from 1 April 2002 until 31 March 2003 equating to a contribution of 15 per cent to overall IBC

[77] Full details can be found in 'Income adjusting event under NGC's 2002/03 system operator incentive scheme, a decision document', June 2003, Ofgem at the following address: http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/3775_Drax_IAE_DecisionvFINAL1.pdf
[78] Full details can be found in 'Income adjusting event under NGC's 2003/04 system operator incentive scheme, a decision document', July 2004, Ofgem at the following address: http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/7765_15304_income_adjusting.pdf
[79] This table shows monthly sums for each IBC component and averaged for each time period.
[80] This table shows monthly sums for each IBC component, averaged per time period as a proportion of the sum of IBC per month, averaged over each time period.

over this period. For financial year 2003/04, this rose to £6.20 million, accounting for 21 per cent of IBC. During the current incentive scheme period, CSOBM has increased to an average of £6.97 million, equivalent to 22 per cent of IBC. This is mainly the result of increased margin actions in September 2004 and October 2004. Over the entire period since NETA go-live, CSOBM has accounted for 19 per cent of IBC, averaging £5.62 million each month.

2.26 Monthly total BSCC averaged £15.67 million for the period from 1 April 2002 until 31 March 2003, which is almost £4.1 million higher than average BSCC under the initial incentive scheme post NETA go-live. Over the course of financial year 2003/04, BSCC rose to a monthly average of £17.13 million, equivalent to 58 per cent of IBC. During the current incentive scheme period, BSCC has averaged £16.12 million, accounting for a smaller proportion of IBC at 52 per cent. BSCC continues to make the largest contribution to IBC of all its components.

2.27 Monthly total TLA averaged £6.73 million for the period from 1 April 2002 until 31 March 2003, accounting for 21 per cent of IBC. This figure fell back to £6.39 million for financial year 2003/04, whilst retaining a 21 per cent share of IBC. Over the current incentive scheme period to 31 October 2004, monthly total TLA has averaged £7.82 million, representing 25 per cent of IBC. TLA has accounted for around 23 per cent of total IBC costs over the entire period from NETA go-live until 31 October 2004.

2.28 Monthly total NIA averaged £4.31 million for the period from 1 April 2002 until 31 March 2003, accounting for 14 per cent of IBC. NIA fell back to a fraction above zero at £0.03 million for incentive scheme 2003/04, before rising slightly for the current scheme. Total monthly NIA has averaged £0.33 million from the period between 1 April 2004 and 31 October 2004. This is equivalent to seven per cent of average monthly IBC over this period.

2.29 Additional detail is provided in the tables below. Table A2.7 presents the monthly values of each of the components of IBC, while Table A2.8 shows each component's monthly percentage contribution to IBC.

Table A2.7 – Monthly IBC component totals (£ million, money of the day)

Month	CSOBM	BSCC	TLA	NIA	IBC

Month	CSOBM	BSCC	TLA	NIA	IBC
Apr-03	1.70	13.50	5.85	2.55	23.60
May-03	4.12	12.07	5.25	-0.57	20.87
Jun-03	5.87	15.30	5.27	0.90	27.34
Jul-03	13.28	19.71	5.44	-2.27	36.15
Aug-03	6.90	12.72	5.86	-0.90	24.58
Sep-03	2.18	14.87	6.25	2.35	25.66
Oct-03	6.56	21.01	7.08	1.19	35.84
Nov-03	6.61	18.34	6.54	3.21	34.71
Dec-03	7.54	20.09	6.90	-0.14	34.39
Jan-04	4.01	20.56	7.40	2.42	34.39
Feb-04	2.18	15.96	7.13	0.63	25.89
Mar-04	13.50	21.39	7.71	-8.95	33.65
Apr-04	1.88	12.48	7.31	2.64	24.32
May-04	2.73	12.39	6.13	4.59	25.84
Jun-04	9.02	14.81	6.20	-0.18	29.85
Jul-04	5.19	15.00	7.02	0.66	27.87
Aug-04	3.94	18.26	8.43	0.45	31.09
Sep-04	8.12	19.70	9.98	-4.12	33.68
Oct-04	17.91	20.17	9.67	-1.73	46.03

Table A2.8 – Monthly IBC components as proportion of IBC

Month	CSOBM	BSCC	TLA	NIA
Apr-03	7%	57%	25%	11%
May-03	20%	58%	25%	-3%
Jun-03	21%	56%	19%	3%
Jul-03	37%	55%	15%	-6%
Aug-03	28%	52%	24%	-4%
Sep-03	8%	58%	24%	9%
Oct-03	18%	59%	20%	3%
Nov-03	19%	53%	19%	9%
Dec-03	22%	58%	20%	0%
Jan-04	12%	60%	22%	7%
Feb-04	8%	62%	28%	2%
Mar-04	40%	64%	23%	-27%
Apr-04	8%	51%	30%	11%
May-04	11%	48%	24%	18%
Jun-04	30%	50%	21%	-1%
Jul-04	19%	54%	25%	2%
Aug-04	13%	59%	27%	1%
Sep-04	24%	58%	30%	-12%
Oct-04	39%	44%	21%	-4%

Appendix 3 Respondents to the Initial Consultation document

3.1 The following is a list of those who provided non-confidential responses to the September 2004 Initial Consultation document:

- Association of Electricity Producers
- British Energy
- Centrica
- EDF Energy
- Edison Mission Energy
- E.ON UK
- National Grid Transco
- RWE npower
- Scottish Power
- Scottish and Southern Energy

Appendix 4 The regulatory framework

Introduction

4.1 This appendix summarises the current regulatory framework for the electricity industry. It outlines the current legislative, licensing and regulatory regimes and describes the relationship between the Electricity Act 1989, the Utilities Act 2000, licences and industry agreements.

The Electricity Act 1989

4.2 The Electricity Act 1989, as amended by the Utilities Act 2000, provides the framework for the functions of the Gas and Electricity Markets Authority (the Authority) in respect of electricity and sets out the licensing regime in relation to the supply, distribution, generation and transmission of electricity.

4.3 Under section 9(2) of the Electricity Act 1989, holders of transmission licences are obliged to develop and maintain an efficient, co-ordinated and economical system of electricity transmission and to facilitate competition in the supply and generation of electricity.

The Utilities Act 2000

4.4 The Utilities Act 2000 introduced a new principal objective for the Authority, as defined in Section 3A of the Electricity Act. The Authority's principal objective in respect of electricity is "to protect the interests of customers in relation to electricity conveyed by distribution systems [or transmission systems][81], wherever appropriate by promoting effective competition between persons engaged in, or in commercial activities connected with, the generation, transmission, distribution or supply of electricity or the provision of use of electricity interconnectors[82]".

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[81] The words 'or transmission systems' were inserted by the Energy Act 2004, section 179(2), however a date has not yet been appointed for this change to come in to force.

[82] The words 'or the provision of use of electricity interconnectors' were inserted by the Energy Act 2004, section 147(2)(a), and this change has been in force from 1 December 2004 (SI 2004/2575).

The Energy Act 2004

4.5 The Energy Act 2004 introduced a requirement that, subject to its principal objective and its general duties, the Authority (and the Secretary of State) should, amongst other things, carry out its functions in a manner best calculated to contribute to the achievement of sustainable development[83].

4.6 The Energy Act 2004 additionally requires that the Authority (and the Secretary of State) should carry out its functions having had regard to "the principles under which regulatory activities should be transparent, accountable, proportionate, consistent and targeted only at cases in which action is needed" and any other principles appearing to represent best regulatory practice[84].

NGC's electricity transmission licence

4.7 NGC owns and operates the national grid in E&W, which transports electricity at high voltage from the generators to the local distribution networks and to customers connected directly to the transmission system. NGC holds an electricity transmission licence which is treated as granted under section 6(1) of the Electricity Act 1989.

4.8 On 26 August 2004, the Secretary of State exercised her powers under sections 134 and 137, and paragraph 1 of Schedule 17, of the Energy Act 2004 to: determine new standard conditions in relation to transmission licences; make a scheme in relation to existing transmission licences; and modify the conditions of licences under section 6 of the Electricity Act 1989. On 31 August 2004, the Secretary of State further exercised her powers under sections 134 of the Energy Act to modify the conditions of transmission licences. The changes came into effect on 1 September 2004.

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[83] Section 83 of the Energy Act 2004 amends section 3A of the Electricity Act 1989 to this effect.
[84] Section 178 of the Energy Act 2004 amends section 3A of the Electricity Act 1989 to this effect.

Standard condition C16[85]

4.9 NGC's transmission licence contains several provisions relating to information provision and transparency:

- standard condition C16(1) requires the licensee to co-ordinate and direct the flow of electricity onto and over the GB transmission system in an efficient, economic and co-ordinated manner; and

- standard condition C16(2) prohibits the licensee from discriminating as between any persons or classes of persons in its procurement or use of balancing services.

Standard condition C16 statements

4.10 NGC is required to procure any balancing services competitively and via transparent processes. In order to fulfil this requirement, NGC is obliged under standard condition C16 of the transmission licence to have in place two particular documents[86]:

- the Procurement Guidelines (PGs), which detail the types of balancing services that NGC may be interested in purchasing, together with the mechanisms envisaged for purchasing such balancing services. Table 3 within Part E of the PGs outlines NGC's approach to providing information relating to its procurement of balancing services in order to provide market participants and other interested parties with sufficient information without compromising the commercial position of any contracting party.

- the Balancing Principles Statement (BPS), which defines the broad principles and criteria by which NGC will determine, at different times

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[85] With effect from 1 September 2004 and following modifications made by the Secretary of State to the electricity transmission licence, what was formerly referred to as special condition AA4 of NGC's transmission licence became standard condition C16 of the electricity transmission licence.
[86] Standard condition C16 obliges NGC to have in place four documents in total; the Procurement Guidelines (PGs), the Balancing Principles Statement (BPS), the Balancing Services Adjustment Data (BSAD) Methodology Statement and the Applicable Balancing Services Volume Data (ABSVD) Methodology Statement. Details of the PGs, the BPS, the BSAD Methodology Statement and the ABSVD Methodology Statement can be found at NGC's website www.nationalgrid.com/uk/indinfo.

and in different circumstances, which balancing services it will use to assist in the operation of the transmission system.

Standard condition C16 reports and audit

4.11 Standard condition C16 further requires ex-post reporting and an assessment of NGC's compliance in order to provide transparency in relation to NGC's actions. Standard condition C16 requires:

- NGC to prepare and publish annually a report in respect of the balancing services it has bought or acquired in the previous 12 months;

- NGC to prepare and publish annually a report on the manner in which, and the extent to which, it has complied with the BPS in the previous 12 months[87]; and

- NGC's auditors to prepare a statement to accompany the BPS review. In this statement, the auditors must provide their opinion as to the extent to which the licensee has complied with the BPS.

Special condition AA5A

4.12 Special condition AA5A sets restrictions on the revenues that NGC is allowed to earn from its Transmission Business. For this purpose, NGC's activities are split between its Transmission Network Services (TNS) and its Balancing Services Activity (BSA).

4.13 The TNS activities are defined as including all NGC's authorised activities relating to the planning, development, construction and maintenance of the transmission system (except for its BSA and excluded services). The BSA covers procuring and using balancing services for the purpose of balancing the licensee's transmission system. As such, the TO carries out the TNS activities whilst the SO carries out the BSA activity.

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[87] A six month report was prepared to cover the period between 1 April 2002 and 30 September 2002, however, future reports will cover a 12 month period and will be produced annually.

4.14 Part 1 of special condition AA5A outlines the revenue restriction in relation to NGC's TNS, while Part 2 outlines the revenue restriction in relation to its BSA.

4.15 The TNS revenue restriction is in the form of an RPI-X price control. The current restriction started on 1 April 2001 and is due to finish on 31 March 2006.[88] The BSA revenue restriction consists of a profit-sharing (sliding scale) incentive scheme, which has separate targets for NGC's internal and external SO costs.

Industry Codes

Balancing and Settlement Code

4.16 NGC is required under standard condition C3 of the transmission licence to prepare the Balancing and Settlement Code (BSC). The BSC came into effect on 14 August 2000. Ahead of BETTA go-live, a suite of modifications was made to the BSC to create a GB BSC as part of the introduction of BETTA. These changes were made by way of designation by the Secretary of State on 1 September 2004.

4.17 The scope of the BSC is defined in general terms in the transmission, generation and supply licences. The BSC is a code that sets out the rules for the Balancing Mechanism and imbalance settlement process in the wholesale electricity trading arrangements and it is maintained by NGC under standard condition C3 of its transmission licence.

4.18 The BSC sets down the arrangements in respect of:

- making, accepting and settling offers and bids to increase or decrease electricity delivered to, or taken off, the total system (NGC's transmission system and the distribution systems) to assist NGC in balancing the system; and
- determining and settling imbalances and certain other costs associated with operating and balancing the transmission system.

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[88] Details of the current revenue restriction can be found in 'The transmission price control review of the National Grid Company from 2001: transmission asset owner, Final proposals', Ofgem, September 2000.

4.19 A BSC Panel has been created and charged with overseeing the management, modification and implementation of the BSC rules, as specified in Section B of the BSC. The Panel has twelve representatives made up from industry members, consumer representatives, independent members and NGC. The Authority appoints the Chairman of the Panel.

4.20 The Balancing and Settlement Code Company (ELEXON[89]) supports the BSC Panel. The primary purpose of ELEXON is to provide or procure a range of operational and administrative services (both directly and through contracts with service providers) and to implement the provisions of the BSC and modifications to it.

4.21 The details of the modification procedures are contained in Section F of the BSC. They are designed to ensure that the process is as efficient as possible whilst enabling as many parties as possible to propose modifications and have the opportunity to comment on modification proposals. Whilst Ofgem can not initiate any modifications, it is required to approve or reject all modifications to the BSC, according to defined criteria outlined in standard condition C3(3) of NGC's transmission licence and its statutory duties. Ofgem's statutory duties are wider than the matters that the Panel must take into consideration and include amongst other things a duty to have regard to social and environmental guidance provided to Ofgem by the government.

4.22 NGC is required under the BSC to provide certain information to the market on an ex-ante basis. For example, NGC is required in accordance with Section Q.6 of the BSC to submit a number of data streams (e.g. the Indicated Margin and the National Indicated Imbalance) to the Balancing Mechanism Reporting Agent (BMRA) on an ex-ante basis. This data is made available for publication on the Balancing Reporting Mechanism Service (BMRS) to provide ex-ante information to market participants, enhancing transparency.

Connection and Use of System Code

4.23 NGC is required under standard condition C10 of the transmission licence to prepare the Connection and Use of System Code (CUSC). The CUSC is a licence-based code, setting out the principal rights and obligations in relation to connection to and/or use of the transmission system and to the provision of certain balancing services. The CUSC was designated by the Secretary of State on 25 June 2001 and came into effect on 18 September 2001. Ahead of BETTA go-live, a suite of modifications was made to the CUSC to create a GB CUSC as part of the introduction of BETTA. These changes were made by way of designation by the Secretary of State on 1 September 2004.

4.24 A CUSC Panel has been charged with overseeing the CUSC amendment process as specified in Section 8 of the CUSC. The Panel has representatives made up from industry members, consumer representatives and NGC. The Chairman of the Panel is appointed by NGC and must be an executive director (or other senior employee) of NGC. NGC is responsible for implementing or supervising the implementation of Approved Amendments as outlined in paragraph 8.2.3.3 of the CUSC. As with the BSC, while Ofgem can not initiate amendments, it is required to approve or reject all amendments to the Code, according to defined criteria outlined in standard condition C10(18) of NGC's transmission licence and its statutory duties. Ofgem's statutory duties are wider than the matters that the Panel must take into consideration and include amongst other things a duty to have regard to social and environmental guidance provided to Ofgem by the government.

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[89] The Balancing and Settlement Code Company was named ELEXON Limited on 7 June 2000.

Appendix 5 NGT paper on cost savings under 2002/03 SO incentive scheme

5.1 This appendix contains a paper prepared by NGT in relation to cost savings under NGC's 2003/04 SO incentive scheme.

BSIS Savings Delivered by NGC in 2003/4

Introduction

NGC's target for Incentivised Balancing Costs for 2003/4 was £416.0m. The outturn cost was £355.6m.[90] This note records the activities we have undertaken by NGC during 2003/4 which contributed to delivering this outturn performance.

We identify the following cost-saving activities, which we developed during 2003/4:

- Trading strategies
- Holding of optional fast reserve
- New constraint contracts
- Refinement of requirements for response and reserve

These are now discussed in turn:

Trading strategies

Since NETA Go-Live, we have always exercised the choice, whether to balance the system with Forward Trades, or in the Balancing Mechanism. Both system and energy balancing requirements are less certain at the day-ahead typical timescale for our Trades, but the Trade prices are typically more attractive for us. In the BM, requirements are more certain, but the prices of balancing actions are less attractive for us. In managing the system, therefore, we balance the more attractive prices available in Forward markets with the shorter term flexibility of trades in the BM.

For 2003/4, we were faced for many months with an unusually severe pattern of Physical Notifications ('PNs'), which caused constraint issues across the entire South of the country. The fact that constraint costs outturned at £31m, above the level of previous years, despite our efforts below, is evidence of this pressure. To manage these constraints, we deployed extra staff to pursue innovative transmission solutions of network re-switches and outage re-scheduling, and to investigate the interaction of these solutions with possible trading strategies. Trading under schedule 7 of a Grid Trade Master Agreement (GTMA), which we term BMU-specific trades, we can ensure that a purchase or sale of energy occurs at a particular location, and such Trades (whilst not as certain of delivery as the BM) can offer us a much more attractive price to solve constraint issues than the BM.

Also in 2003/4, we refined our Energy trading strategy, to recognise the extent to which forward Trade sales, whilst balancing a long system cheaper than in the BM, can increase the need for 'margin' actions to secure operating reserves. As a result of this refinement, we actually forward traded less of the system length than in the previous year. By recognising the Margin impact of our Trades, we were able to avoid certain dis-benefits of previous years.

We review all Trading decisions on a daily basis, and derive the benefit against alternatives in the BM. In all cases, we have erred on the conservative side in judging the effect of the alternative – for example, we have assumed the cheapest alternative in the BM would be fully effective (which is not always the case), and we have included the margin dis-benefit of forward Sales. On this conservative basis, the aggregate benefit of our BMU-specific and Energy trades was at least £8.9m.

Holding of Optional Fast Reserve

We have a requirement to hold between 300MW and 900MW of Fast Reserve, strongly dependent on time-of-day and time-of year. Over 2002/3, our total holding of Fast Reserve amounted to 2660GWh, at a holding cost of £31.1m. In 2003/4, our Control Room:

- Focussed on only holding Fast Reserve at times of day when it is most useful; this is evidenced by the fact that the utilisation ratio (the fraction of MWh of Fast Reserve utilised over the MWh held) rose from 6% to 9% across a large class of providers;
- Redoubled efforts to hold and use a range of providers of Fast Reserve; for example the fraction of demand-side costs rose from ~10% to ~20%;
- Tightened holding, by managing for many hours without any 2-minute Fast service, and relying on good despatch to be able to make use of 5 minute BM services.

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[90] The £355.6m does not include the impact of the Income Adjusting Event.

In consequence, in 2003/4, we held 1900GWh of Fast Reserve, at a holding cost of £24.3m. The 29% reduction in volume would have led to an equivalent reduction in cost, had we not had to concede to holding price rises across a number of providers, and so the effective saving, including both the volume reduction and the pricing pressure, amounts to £10m.

New Constraint Contracts

As mentioned above, an unusually severe pattern of Physical Notifications caused constraint costs to outturn at £31m, above the level of previous years. We managed to negotiate some new Constraint contracts to handle these conditions, and these contracts saved £12m off what Constraints would otherwise have cost.

Refinement of Response and Reserve Requirements

Our principle requirements for response and operating reserve have evolved over many years, to a level that is close to the minimum necessary for system security. During 2003/4, we managed to refine requirements in two respects. Detailed review of the frequency performance of the system enabled us to reduce our minimum requirement for dynamic response, over the less 'stressful' times of day of low rate of change of demand. Our better understanding of short term plant losses enabled us to target the reserve holding more effectively for the period between 0600-1100, leading to a reduction of overall reserve requirements. This refinement delivered a saving of £3m during 2003/4.

Conclusion

In summary, we identify savings resulting from these within-year activities as follows:

• Trading strategies	£9m
• Holding of Optional Fast Reserve	£10m
• New Constraint contracts	£12m
• Refinement of response and operating reserve	£3m
TOTAL	£34m

These savings show that we continue to deliver value under our Incentive scheme on balancing costs. Half of these savings were passed directly through to customers under the within-year sharing factor, and these savings will be passed fully through, as their effect is reflected in future years' scheme targets.

Appendix 6 NGT paper on 2005/06 forecast

6.1 This appendix contains a paper prepared by NGT which outlines the basis for its forecasting approach and provides details relating to the forecast itself.

Appendix B NGT's Forecast of Incentives Balancing Costs for Great Britain in 2005/6
B1. Introduction and Assumptions

This appendix presents our forecast of Incentivised Balancing Costs (IBC) for Great Britain in 2005/6.

In developing a GB IBC forecast, we have extended our existing forecasting models to include the Scottish system. The forecast process starts from a breakdown of historical balancing costs on an England and Wales basis. We then consider how these costs might change in the future – that is, we extrapolate future cost scenarios based on experience of past costs.

Under the British Grid System Agreement (BGSA), Scottish Power Transmission Limited (SPTL) and Scottish Hydro Electric Transmission Limited (SHETL) carry out system balancing actions in their respective area in proportion to their system size. The costs of these balancing actions are currently internalised and will be revealed under BETTA. Our bottom-up forecasting approach starts with analysing the magnitude of these balancing activities, including constraints, whose costs are currently internalised within SPTL and SHETL. The results obtained, together with historical performance of IBC in E&W, form the basis of our forecasts. The impact of BETTA on market competition and participant behaviours is captured in our scenarios.

This appendix begins by explaining the forecast method, and then looks at the historic performance of the drivers of IBC. Then the scenarios developed by NGC for the forecast are discussed, followed by the issues considered in expanding the forecast to cover all of GB, rather than England and Wales, as considered in previous years. The appendix then discusses each element of the forecast before presenting the overall forecast of GB balancing costs for 2005/06

Assumptions
We assume in our forecasts that:

- BETTA is fully implemented on 1st April 2005.

- The general scope and form of the incentive scheme remains the same as the 2004/5 England and Wales SO incentive scheme.
- The Transmission Losses Reference Price (TLRP) is £21/MWh.
- There are no other BSC modifications or CUSC amendments, beyond those already approved that would have a material impact on GB balancing costs.
- There is no explicit inclusion of costs resulting from the implementation of CAP048 (Firm Access and Temporary Physical Disconnection) or CAP070 (Short Term Firm Access).

B2. Forecasting Method

We have to forecast the term IBC, which is defined in NGC's transmission licence as:

IBC = CSOBM – NIA[91] + BSCC + TLA[92]

Where

- CSOBM represents total costs incurred in the Balancing Mechanism (BM) minus the cost of non-delivery;
- BSCC represents balancing services contract cost. It includes ancillary services and trading costs;
- NIA is the net imbalance adjustment;
- TLA is the transmission loss adjustment, and is defined as the product of transmission losses volumes and the transmission loss reference price (TLRP);

For modelling purposes, the above is re-arranged as follows

IBC = IBMC' + Trade' + AS' + TLA + Constraints

Where

- IBMC' represents incentivised balancing mechanism costs excluding constraints incurred in the BM, and is defined as BMC' – NIA;
- BMC' represents balancing mechanism costs excluding constraints incurred in the BM;
- Trade' represents all pre-gate trading costs excluding constraint costs in trades;
- AS' represents ancillary service costs excluding constraint costs incurred through balancing services contracts;
- Constraints represent total costs of actions taken for constraint management purposes in the BM, trades and ancillary.

[91] NIA here is defined as NIVxNIRP, where NIV=-TQEI. Thus, this is the opposite sign convention from the licence definition, which is TQEIxNIRP.

The forecasting approach used to estimate the above IBC components is a scenario based extrapolation method. Constraint costs are forecast, by scenario where required, through a combination of detailed network analysis, risk assessment and probabilistic modelling as described in section B8.

We consider that the GB IBC is primarily driven by the same key cost drivers as E&W IBC. They are

- Forward electricity prices
- BM Prices – average accepted BM bid and offer prices
- Net Imbalance Volume (NIV) or Market Length
- Free Headroom – the level of part loaded plant delivered by the market at the gate closure
- Plant margin
- Flows across the Anglo – French Interconnector

There are other cost drivers that influence GB IBC indirectly but are not explicitly included as one of the key cost drivers. For example, fuel prices indirectly impact on IBC through the effect of forward electricity and submitted BM bid/offer prices.

Different drivers impact on balancing costs in different ways. For example, market length or NIV impacts primarily on energy balancing costs in the BM and NGT's forward trades. Free headroom mainly affects system balancing costs; especially, warming and margin in the BM. Market length and free headroom also combine to produce a much larger effect on IBC.

The historical and future performance of the above key cost drivers is an important factor in our scenario formulation and forecasting process. This is described in the following section.

B3. Historic Driver performance

Net Imbalance Volume (NIV)

NIV is the net position of the market, and is dependent upon a number of factors including suppliers' demand forecasting accuracy, supplier risk profile and risk management strategy. The market is generally long (negative NIV) due to asymmetric risks associated with the dual cash-out pricing arrangements.

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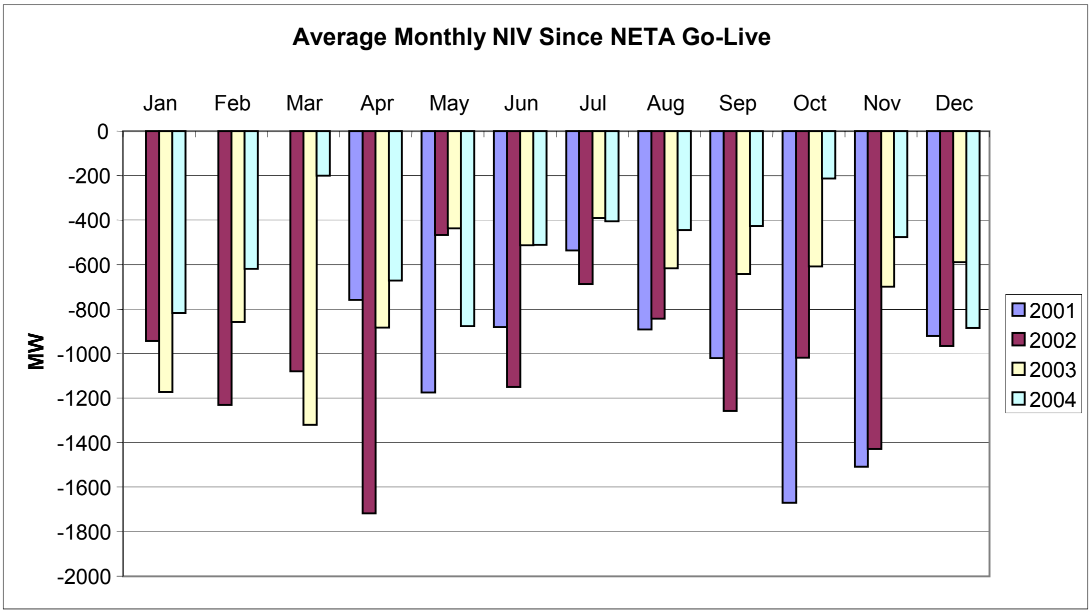
[92] The Formal Licence definition includes the terms OM and RT, which are both forecast to be £0 for 2005/06

NIV is normally distributed and directly determines the volume, hence the costs, of bids and offers NGC have to take to balance the market. It also affects the operating margins available to NGC at gate closure.

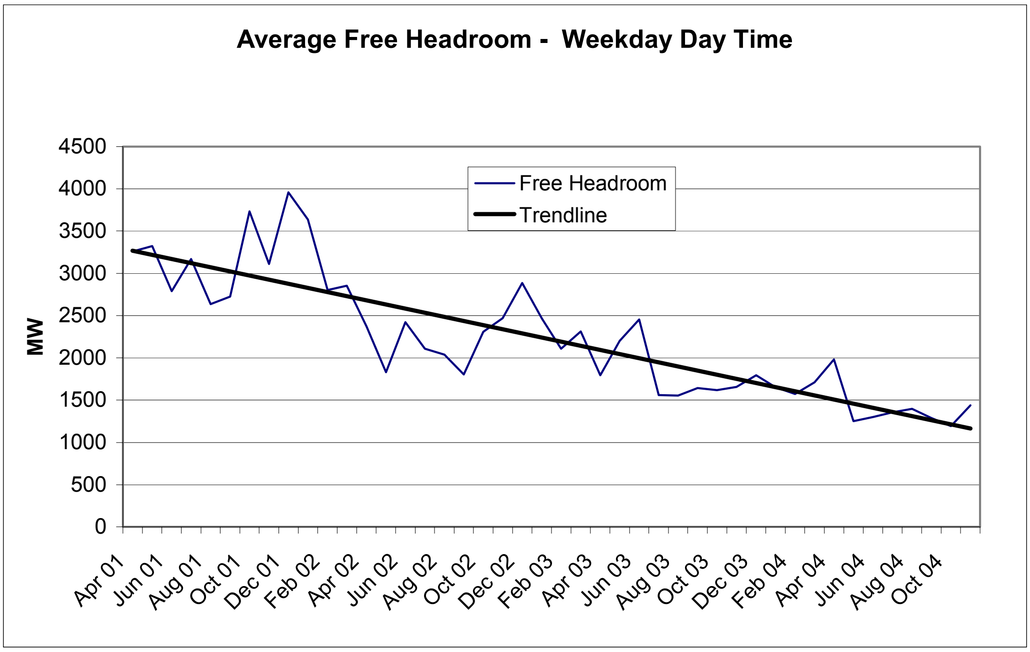
NIV has fallen significantly since the adoption of BSC Proposal P78 (Revised definitions of System Buy Price and System Sell Price), as shown in the diagram below. However, in contrast, the standard deviation of NIV has not changed significantly in the same time period. This suggests that the market has become more efficient due to lower market risks rather than better demand forecasting by suppliers. In summary, the market has become significantly shorter than prior to the implementation of P78.



Free Headroom.

Free Headroom is the level of part loaded plant delivered by the market at gate closure. It contributes to meeting NGC's short-term system operating margin requirements. Therefore, the level of free headroom directly impacts on the cost of margin.

Free headroom displays a clear downward trend since the implementation of NETA, with a year-on-year reduction of approximately 25%. This trend implies that the market appears to be becoming more efficient with less part-loaded plant on the system, reducing the amount of plant available to provide system reserve. The diagram below illustrates the reduction in free headroom that has been observed since NETA "Go-Live".

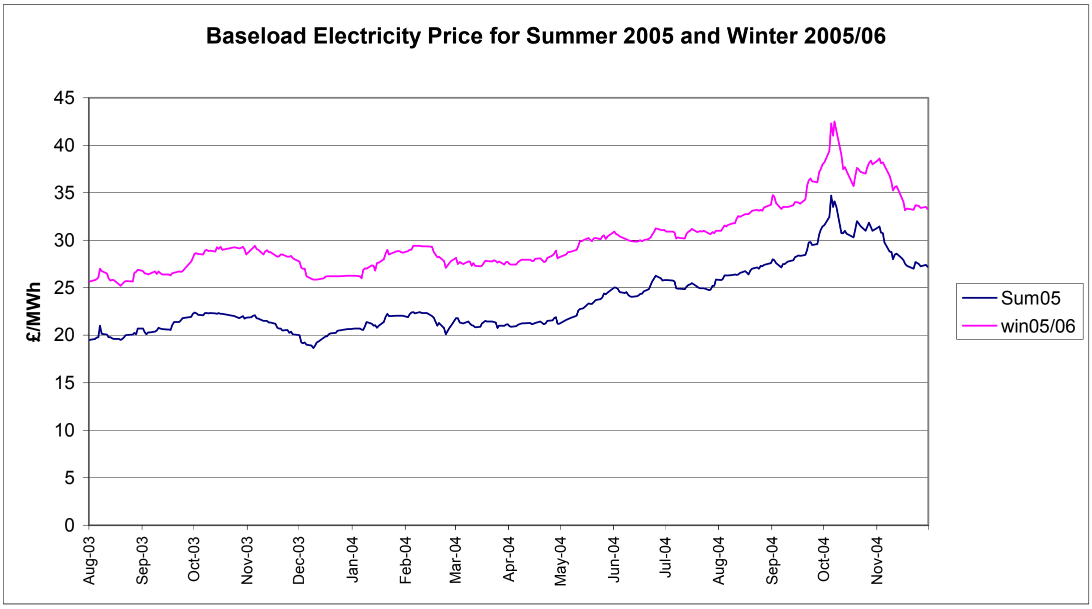


The above graph shows a clear downward trend in free headroom since NETA Go-Live. November 2004 has been the lowest monthly average free headroom at 1200MW. We believe that this trend will continue until it reaches the minimum as determined by generation and demand characteristics.

Forward Price.

Forward electricity prices impact on GB IBC in a number of ways including the costs of NGC pre gate trades and flows across the Anglo-French interconnector.

Since September 2003, the forward price of electricity has increased significantly. A key factor in this is significant increases in fuel prices.



The forward price has fallen sharply from its peak and is now back to its pre-winter value. Whether this heralds the start of a downward trend into 2005/06 is not clear. But we note that the forward price went through a similar correction in winter 2003/04 where it also fell by mid-winter to its pre-winter level, and then stabilised and rose sharply in the following months. The current average baseload forward price for 2005/06 is £29.9/MWh[93]. This supports our scenario mean of £29/MWh, as discussed in section B4.

BM Prices.

The accepted BM bid and offer prices depend on the submitted bid and offer prices and the amount of actions taken by NGC to balance the system. They directly impact on the costs of actions taken in the BM.

The BM bid market is highly competitive, with a large volume of bids accepted. Consequently, bid price trends closely follow fuel price trends. The BM bid price has risen by approximately 40% since September 2003 reflecting the increase in fuel prices, as shown in the diagram below.

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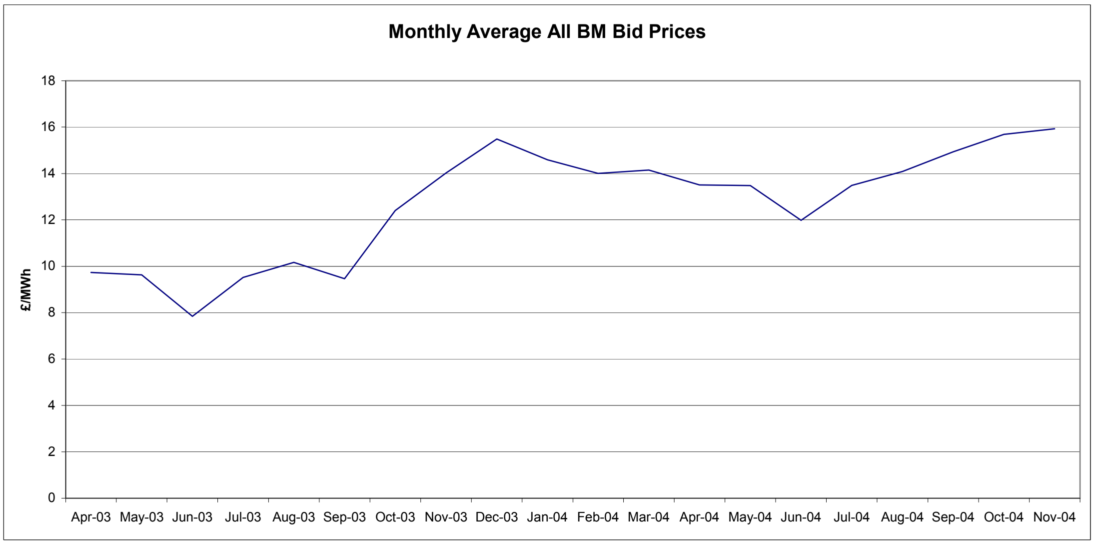
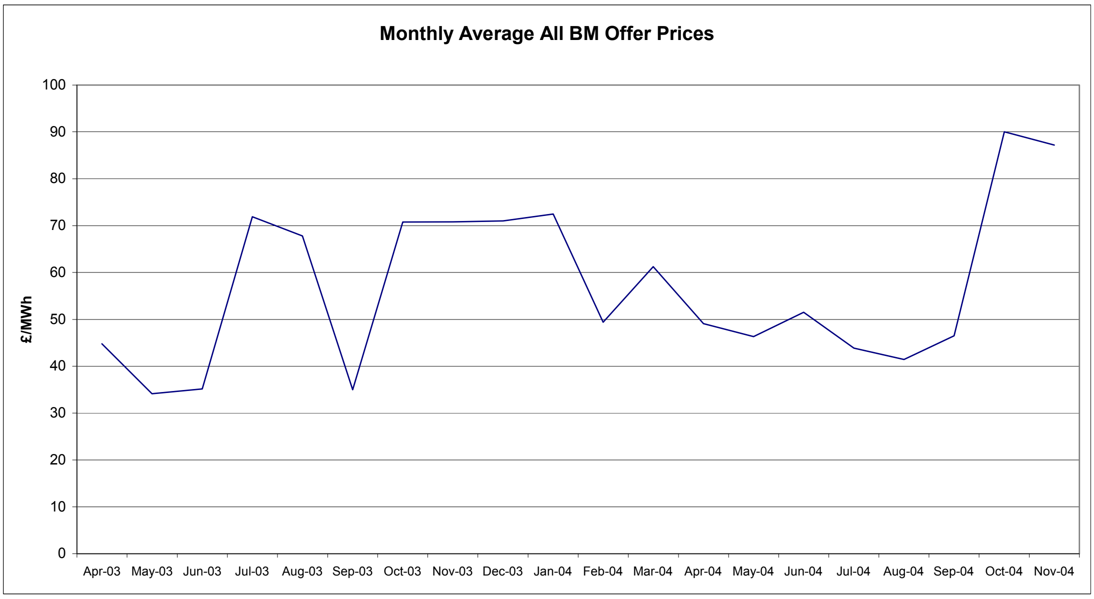
[93] Mid-price as reported in Argus European Electricity Report, 14th December 2004.



The average bid price is seasonal, and has risen sharply since June 2003, reflecting higher fuel costs. The highest monthly average bid price is £16/MWh in November 2004. However, on an annual basis, the average is around £14~15/MWh.

In contrast, the average accepted BM offer price is highly volatile from month to month depending on market conditions and actions, such as the amount of margin actions taken by NGC. The diagram below illustrates the volatility in BM offer prices.

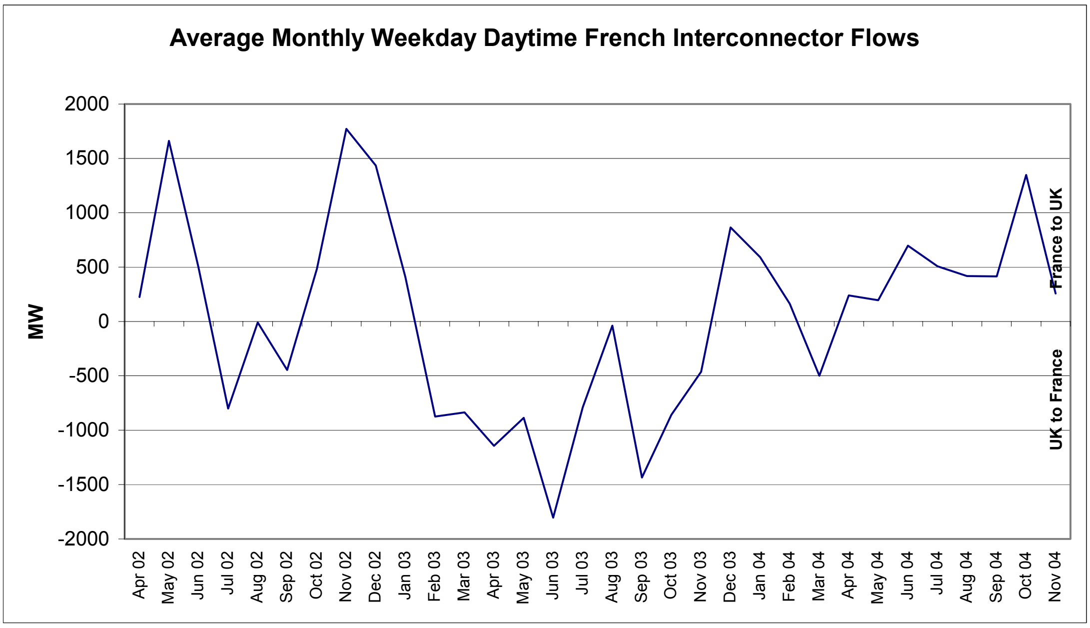


The average Offer price is seasonal. October 2004 has seen the highest monthly average accepted offer prices since the start of NETA, at around £90/MWh.

French Interconnector Flows.

Flows across the Anglo-French interconnector depend primarily upon the price differentials between E&W and continental Europe. UK export to France has a significant impact on the constraint costs across the south and south east of the system.

As mentioned above, forward prices in E&W have risen much faster than in Europe since September 2003. Prices are now broadly similar or slightly higher than those in Europe. Consequently, the interconnector flow has changed from UK export last year, to float or moderate UK import this year, as shown in the diagram below.



Of course, French interconnector flows may reach the maximum export limit for some days or certain periods of the day. However, the average flow for working day daytime is very unlikely to reach the maximum on a monthly basis because of different within day price profile between UK and Europe and also planned outages on the link. Indeed, it can be seen from the above graph that the average monthly interconnector flow has only exceeded 1000MW UK import for 4 months since April 2002.

B4. Scenarios

We have developed a robust scenario construction process. This involves a careful analysis and monitoring of key cost driver performance, (as described in section B3 above) reviewing market developments, and collation of market intelligence. When the scenarios were developed, we only had cost driver data up to September 2004. We have updated the graphs in B3 with data from October and November. We believe that this is useful as it shows the underlying trends in the drivers since the scenarios were constructed, and that the extra data reinforces the magnitude and range of driver values in our scenarios.

In order to forecast GB balancing costs, we have constructed six credible scenarios, reflecting likely market conditions and participant behaviours in 2005/06. These scenarios form the basis of our forecast. Each scenario is considered independently and represents a possible market condition, though some are assigned a higher probability of occurrence than others.

Scenario Characteristics

Scenario 1- As Was.

In this scenario, the market behaves as it did during the period of September 2003 to August 2004. This is despite the implementation of BETTA and recent changes in ownership of a large amount of generation in England & Wales (in excess of 7.5GW). There is no major change in generator behaviours observed. Following a slowdown in the global economy, fuel prices will fall from current high levels, restoring the electricity price differential between the UK and Europe to levels seen previously. Plant margin is at 24%[94]. Both market length and free headroom increase due to the implementation of BETTA and the inclusion of Scottish suppliers and generators.

Scenario 2 – Self-Restraint

With the implementation of BETTA, the market is cautious and exercises “self-restraint” with no significant increase in competition or targeting of market share by participants. Market participants continue to fine-tune their operating strategies. Fuel prices drop slightly and forward electricity prices are £27/MWh. There is some plant

[94] Plant margin is derived from Seven Year Statements published by Scottish Power (April 2004), Scottish Hydro Electric (June 2003), and National Grid. This was before the interim GB Seven Year Statements became available, which has a slightly lower plant margin (23%) primarily caused by a higher forecast GB demand.

mothballing leading to a drop in plant margin to 22%. Free headroom falls by 5%, as generators improve their despatch and risk management strategies. The forward price, coupled with low BM price volatility, reduces NIV by 10%.

Scenario 3 –Market Share.

Under this scenario, there is no mothballing or closure of plant, leading to a plant margin of 24%. The advent of BETTA sees a significant increase in market competition with participants targeting market share both in the forward market and in the BM. The forward price falls to £23/MWh, which encourages suppliers to go long, increasing market length by 40%. Free headroom increases by 30%, as more plant competes in the BM. Though the forward electricity price falls in Europe as well, it falls faster in the GB market due to increased competition, resulting in increased interconnector flows from the UK into France.

Scenario 4 - As Now.

This scenario is characterised by high forward prices and high plant margin despite the fragmented nature of the market. Plant margin remains at 24%, and fuel prices remain around their current levels, with a forward price of £30/MWh. This forward price dampens market length, although this is offset by the addition of Scottish market participants, leaving market length broadly unchanged. Free headroom falls by 15%, as generators continue to reduce the level of part-loaded plant. The interconnector remains at float in summer, with moderate UK import during winter.

Scenario 5 - Fuel Pain.

Under this scenario, fuel prices rise significantly, reflecting higher demand, political tensions and a high cost of carbon, leading to a forward price of £36/MWh. This forward price discourages suppliers from over-contracting, leading to a fall in NIV of 30%. Following recent retail price rises suppliers are under pressure not to raise prices further, leading to suppliers' margins being squeezed. Generators' margins are also squeezed due to higher fuel costs, and the least efficient plant withdraws from the market, leading to a reduction in plant margin to 23%. The less efficient remaining plant competes in the BM for income, and BM prices become more volatile. Prices in E&W are generally higher than in Europe, hence the predominant flow on the interconnector is into the UK.

Scenario 6 – Gradual Consolidation.

The general theme of this scenario is one of gradual consolidation of the generation market into a few vertically integrated players. The consolidation sees the withdrawal of the less efficient plant, and a less volatile market. Plant margin is at 21%, and forward prices are £33/MWh, which in turn exerts an upward pressure on BM prices. Against the background of a less volatile market, suppliers are better able to manage their risk profiles. Market length drops by 20%. In this consolidated market, generators achieve further reductions in free headroom of 25%.

The table below summarises all of the scenarios and shows the probability that NGT has attached to each of them.

2005/06			**Scenario Number and Probability**						
			1	**2**	**3**	**4**	**5**	**6**	**Mean**
Driver of IBC		**As Was**	**10%**	**20%**	**10%**	**30%**	**15%**	**15%**	
Forward Price (£/MWh)		**24**	24	27	23	30	36	33	**29**
BM Prices (£/MWh)	**Offers**	**54**	54	58	53	61	66	63	**60**
	Bids	**13**	13	14	12	15	17	16	**15**
NIV (MW)	Summer	**-600**	-660	-540	-840	-610	-420	-480	**-576**
	Winter	**-500**	-550	-450	-700	-510	-350	-400	**-481**
	Equinox	**-700**	-770	-630	-980	-710	-490	-560	**-672**
Free Headroom (Daytime) (MW)		**1870**	2050	1780	2430	1590	1500	1400	**1716**
Plant Margin (%)		**22**	24	22	24	24	23	21	**23**
SP Average France to UK Flows (Wk day daytime) (MW)	Summer	**150**	-150	0	-300	300	500	300	**165**
	Equinox	**-330**	-330	-124	-500	100	700	500	**102**
	Winter	**500**	500	700	300	900	1200	1000	**820**

Notes:

All "As Was" figures are validated.

As was = Aug 03 – Jul 04

Plant Margin, NIV and Free Headroom adjusted to take into account the effects of Scottish generators and suppliers.

The scenario probabilities reflect our views on the likelihood of each scenario occurring in 2005/06, taking into account the emerging trend in key IBC cost drivers, market development, and market intelligence. In NGC's view, these scenarios represent a reasonable range of possible outcomes, and the weighted average of the parameters is reasonable against the current background.

B5. Balancing Issues

Overview

In considering GB balancing issues and the resulting change in balancing costs, we believe it helpful to compare the size of systems in E&W, Scotland and GB. This is shown in the table below:

GB Balancing – Overall Metrics (2003/04)

	E&W	Scotland	GB	Scotland as % of E&W
Annual Energy (TWh)	309	34	343	11.0%
Peak Demand (GW)	54.6	5.9	60.5	10.8%
Generation Capacity (GW)	61.7	10.2	71.9	16.5%
Generation (TWh)	305.3	42.2	337.5	13.8%

The GB system is 11.0% larger than the E&W system on a demand basis, or 13.8% - 16.5% bigger on a generation basis.

At present, NGC, SPTL and SHETL each carry out system balancing activities within their own area, and in proportion to their system size. For many balancing services, the appropriate proportions are currently determined under the BGSA.

Under BETTA, the balancing activities currently performed by SPTL and SHETL will be carried out by NGC as GBSO. The costs of these, currently internalised within SPTL and SHETL, will be revealed within GB IBC.

In order to forecast the costs of these activities, we first consider the volumes of balancing services required on a GB basis, service-by-service. The prices, and resulting costs, are considered in the following sections.

GB Balancing – Response

Under the BGSA for 2004/5, the Scottish companies hold 10.7% of the GB response requirement. This equates to 11.9%[95] of the current E&W holding. The current E&W holding of primary response totals 7.9TWh of response.

After the implementation of BETTA, the GB Response requirement will not change, but the GBSO will be required to pay for the response currently held on Scottish generation plant. Based on the figures quoted above, this equates to the GBSO paying for an extra 940GWh of primary response. We expect to hold this extra requirement across a mixture of new mandatory contracts with Scottish generators, additional (or diminished) existing E&W provision, and new commercial contracts with Scottish pumped storage stations.

Overall, the increase of 12% in response paid for by the GBSO is a natural consequence of moving to BETTA.

GB Balancing – Footroom

'Footroom' actions are required in the BM, typically over demand troughs, in order to meet our requirements to hold high frequency response and to have sufficient downward regulation available to us to meet a sudden drop in demand. Plant that operate at their minimum stable export limit have no high frequency regulating capability, and footroom actions involve taking bids on such inflexible plant, and replacing with more flexible plant.

The Scottish plant mix, with four AGR sets, contains a greater fraction of inflexible plant than E&W, and this fraction will increase as more wind generation capacity commissions. Based on our analysis of the consequent balance between inflexible generation levels and trough demands on the GB basis, we believe that the volume of footroom actions required in the BM will increase by approximately 58%, over the relatively low level currently required in England and Wales.

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[95] The ratio of 10.7% of GB response held in Scotland to 89.3% of GB response held in England and Wales gives Scottish response holding as 11.9% of current England and Wales response holding.

GB Balancing – Fast Reserve

Scottish generation currently holds a considerable volume of Fast Reserve, which we estimate to be about 20% of the E&W total. Under BETTA, the total GB requirement of Fast Reserve will be about 111% of E&W levels. It is expected that this requirement will be met through new contracts with Scottish generation and increased optional holding on plant across GB. With the advent of Scottish providers, we expect prices for Fast Reserve to remain constant in real terms, containing an upward price trend in E&W.

GB Balancing – Reserve and Margin

Our requirement for operating reserve in E&W is set from the statistics of short-term plant loss and demand forecast error. A typical value, at 4 hours ahead for winter peak is 3500MW.

We will set our GB requirement for operating reserve in exactly the same way. The derivation is summarised in the footnote below, and the overall requirement for GB operating reserve comes out at a 9% increase on that for E&W.[96] This increase is rather lower than the sum of the operating reserves held by the three SOs currently, and reflects an efficiency benefit of BETTA in centralising the derivation and procurement of operating reserve.

We forecast that this additional requirement will be met through procuring additional standing reserve and reserve actions in the BM. Thus we will purchase 9% more volume of standing reserve, and we will take 9% greater actions in the BM or in Trades to secure Reserve (also known as margin actions).

GB Balancing – Reactive

The volume of leading plus lagging from E&W generators, which is paid under CUSC Reactive arrangements, amounts to 25 Tvarh per annum. Our estimate of the

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[96] The mean of plant loss for the GB system is 12% greater than the mean for E&W, in line with the increase in system size. The standard deviations of plant loss, and also the demand forecast error, are shown to increase by 6%, in line with the square root of the system size increase. The response requirement and thus the requirement for frequency reserve to carry the response, also increases by 12%.

Our E&W requirement for operating reserve can be summarised:

E&W Requirement = Mean of plant loss + 2.78 × Standard deviation + Frequency reserve
= 700MW + 2.78 × 700MW + 900MW = 3540MW

Then our GB requirement for operating reserve can be derived from the same formula:

GB Requirement = 700MW × 1.12 + 2.78 × 700MW × 1.06 + 900MW × 1.12 = 3850MW

Thus, increase of GB requirement, as a fraction of E&W requirement, = (3850-3540) ÷ 3540 = 9%

equivalent volume from Scottish generators (based on information from SHETL and SPTL and historical data) is currently 4.6 Tvarh – we forecast that this will increase to 5 Tvarh next year, with the increased system flows from remote windfarms.

Reactive power output from Scottish plant is around 20% of that from plant in England and Wales, which is large in comparison to the relative size of the system. This is not unexpected, as the Scottish transmission networks contain relatively little reactive compensation, and more closely resemble the CEGB system of the 1980s than the current NGC system. The entire reactive duty on the Scottish networks, therefore, has to be undertaken by the generators, explaining the high volume of reactive power output from Scottish generators.

GB Balancing – Black Start

Current Black Start arrangements in Scotland rely on certain stations to initiate system restoration, with additional restoration services available from further stations. We expect to sign appropriate Black Start contracts to maintain the same level of system security as is provided in England and Wales. Exact details of these contracts await the outcome of commercial negotiations, which have only just commenced.

B6. Ancillary Forecast

Historical costs and volumes of Ancillary services[97] are reported in our monthly Procurement Guidelines reports, and extensively to Ofgem. This year, we have developed our AS forecast model, to be consistent with this reporting, and with the approach adopted for other components of IBC. Our forecast model starts from the historic prices and volumes over a base period. For Ancillary, our base period is April 2003 to March 2004[98]. The model then extrapolates both prices and volumes, service-by-service, into the forecast period April 2005 to March 2006.

The main volume drivers of the extrapolation follow the discussions of GB balancing issues in section B5 above. For example:

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[97] The Licence defines the term BSCC – Balancing Services Contract Costs. For our forecasting purpose, we consider this term in two parts: BSCC = Ancillary + Trades. The cost of Trades is considered in section B10, because it interacts so heavily with the costs in the BM. The remaining costs within BSCC are termed Ancillary, because they equate almost exactly with the costs of Ancillary contracts, as defined since Vesting.

[98] This base period for Ancillary is different from the base period for IBMC+Trade, which is Aug 03-Jul 04. This difference does not matter since the forecasts take this into account. We keep a base period of Apr03-Mar04 for Ancillary, to be visibly consistent with end-year reporting. We use a base period of Aug03-Jul04 for IBMC+Trades, because for these it is important to be as up-to-date as possible.

- Response: volume of GB Response is 12% more than E&W;
- Operating, and thus Standing, Reserve: GB volume is 9% more than E&W;
- Fast Reserve: GB volume is 11% more than E&W;
- Reactive: GB volume is 20% more than E&W.

Price drivers are considered in the service-by-service discussion of costs below, but some common price drivers include:

- RPI: is specifically included in the contract form for most mandatory Ancillary services, and our forecast RPI increases by 5.5% for 2005/6 on 2003/4;
- Where a commercial service competes directly with a mandatory service, for example in Response, then the initial price forecast for that commercial service reflects the RPI assumption for the mandatory service;
- For a number of Reserve services, which are currently subject to rising pricing pressures in England & Wales, we assume that the advent of Scottish providers will contain prices to this year's levels.

Our mean forecast for Ancillary services is summarised in the table[99] below. The table shows the historic costs of each service for 2001/2 to 2003/4, our projection for E&W in 2004/5, and our forecast for GB in 2005/6.

Summary of Forecast Ancillary Services Costs for 2005/06 (£m)

	2001/02	**2002/03**	**2003/04**	**2004/05**	**2005/06**	**Variance to 04/05**
Reactive	38.1	33.0	33.5	39.0	58.5	19.5
Response	63.6	58.2	44.5	50.0	58.8	8.8

[99] This Table excludes the costs of Ancillary Constraints, which are forecast in section B8, and also the energy costs of Ancillary SO-SO trades, which are forecast in section B10.

CAP047	0.0	0.0	0.0	0.0	14.7	14.7
Standing Reserve	20.1	22.5	42.5	49.7	56.0	6.3
Fast Reserve	16.7	30.8	18.7	19.9	22.0	2.1
Other Reserve	6.6	4.5	4.2	4.9	5.8	0.9
Warming	9.0	30.4	21.1	21.2	23.2	2.0
Black Start	9.1	9.8	10.1	12.4	14.9	2.5
AS Other	6.7	10.7	2.9	2.8	3.0	0.2
Total	**169.9 (E&W)**	**199.9 (E&W)**	**177.5 (E&W)**	**199.9 (E&W)**	**256.9 (GB)**	**57.0**

This forecast is now discussed on a service-by-service consideration of costs.

Response

Costs for Ancillary Response for E&W in 2004/5 are projected to outturn at £50m. After purchasing an additional 12% volume from an appropriate mix of mandatory and commercial sources, subject to RPI as noted above, our forecast for Ancillary Response for GB 2005/6 is £58m. This forecast excludes any effect of CAP047, which is considered separately in section B7.

Standing Reserve

For E&W in 2004/5, we have contracted 2106MW of standing reserve capacity, at an ancillary cost projected to be £35.1m. This cost comprises £33.7m of availability fees, plus £1.4m of utilisation payments to non-BM providers paid via Ancillary. For GB in 2005/6, as explained under 'Balancing Issues' above, we forecast to buy an additional 9% of volume, thus 2300MW in total. We expect E&W tenders on average to increase in price, in line with recent years' experience, but we also expect the advent of a number of Scottish providers to cap the maximum price we have to pay to procure the larger volume. Overall, our forecast for Ancillary Standing Reserve for GB 2005/6 is £41m.

For E&W in 2004/5, we have purchased 860MW of supplemental standing reserve, at an availability cost of £15m. The prices of the alternative margin actions in the BM have risen to the point where this is now economic. For 2005/6, we forecast to buy a similar volume, which varies by scenario between 580 and 950MW depending on scenario Plant Margin and Free Headroom. The availability cost of this, which varies between £8 and £18m, in all scenarios substitutes money which would otherwise be spent on margin actions in the BM.

Fast Reserve

Costs for Ancillary Fast Reserve for E&W in 2004/5, across firm and optional sources, are projected to outturn at £20m. After purchasing an additional +20% volume from an appropriate mix of firm and optional sources, and factoring in additional competition from Scottish providers, our forecast for Ancillary Fast Reserve for GB 2005/6 is £22m.

Other Reserve

Within Ancillary, we also spend £5m on other reserve services, such as Fast Start payments to OCGTs and pumped storage, which do not fit into the above categories. Allowing for the likely necessary payments to Scottish pumped storage stations, we forecast to spend £5.8m on Ancillary Other Reserve for GB 2005/6.

Warming

The cost of warming contracts, which keep gensets in a state of dynamic readiness consistent with our Reserve requirements over 24 to 4 hours out, are projected to outturn at £21m for 2004/5. For 2005/6, we will purchase an additional 9% volume, in line with the increase from E&W to GB requirements for operating reserve, and we expect the advent of Scottish providers to contain prices to current levels. Hence our forecast for Ancillary Warming for GB 2005/6 is £23m.

Reactive

Following the implementation of CUSC amendment CAP045, the price of default reactive utilisation is now 50% indexed to power prices. Tenders seeking reactive market contracts factor in the full default price into their tendered prices. The chart in section B3 shows that power prices have risen significantly over the last 8 months, and our scenarios forecast that on average power prices next year remain at current high levels. Combining this large price increase with the 20% increase of Scottish reactive volume, our forecast of reactive costs rises from £39m this year to £58.5m next year.

Black Start

Costs for Black Start services for E&W are rising from £10.1m in 2003/4 to £12.4m this year, because of costs of new providers, and refurbishment and testing of existing providers. Factoring in further such increases in E&W, and costs of new Scottish providers, our forecast for Black Start for GB 2005/6 is £14.9m.

Constraints and SO-SO Energy

Costs for Ancillary Constraints are subsumed into the forecast of Constraints in section B8. Also the costs of 'SO to SO trades' across the French Link, which in outturn are reported as an Ancillary cost, are subsumed into the forecast of IBMC+Trades in section B10.

Ancillary Other

Each year, we incur miscellaneous other Ancillary costs, which include Trading fees, and liabilities for services used which we do not manage to settle within-year. These costs have declined from approximately £5m for the first two years of NETA to £3m currently, and we forecast costs to remain at this level next year.

B7. Response Market (CAP047)

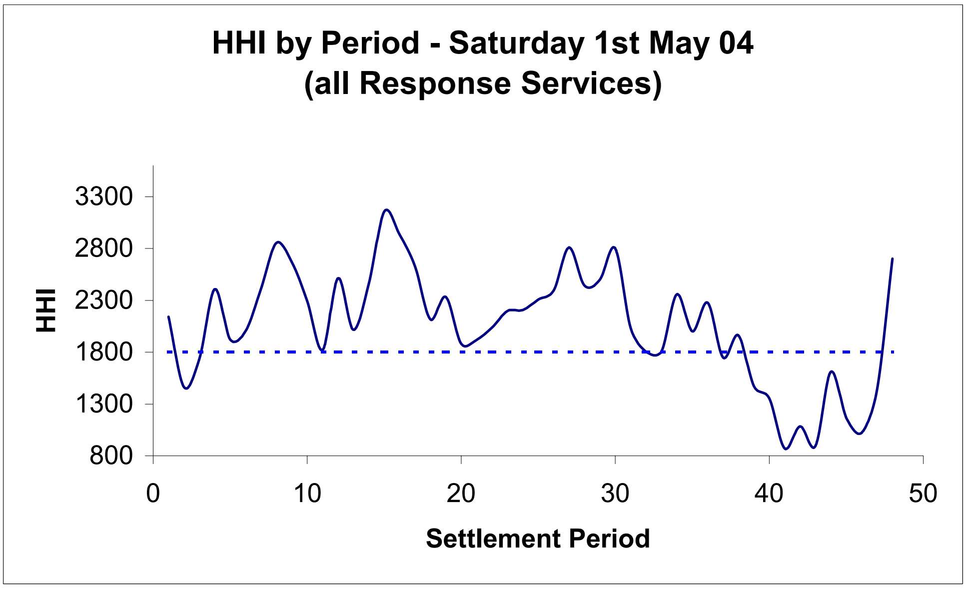
The above forecast of Ancillary costs specifically excludes any effects of CAP047.

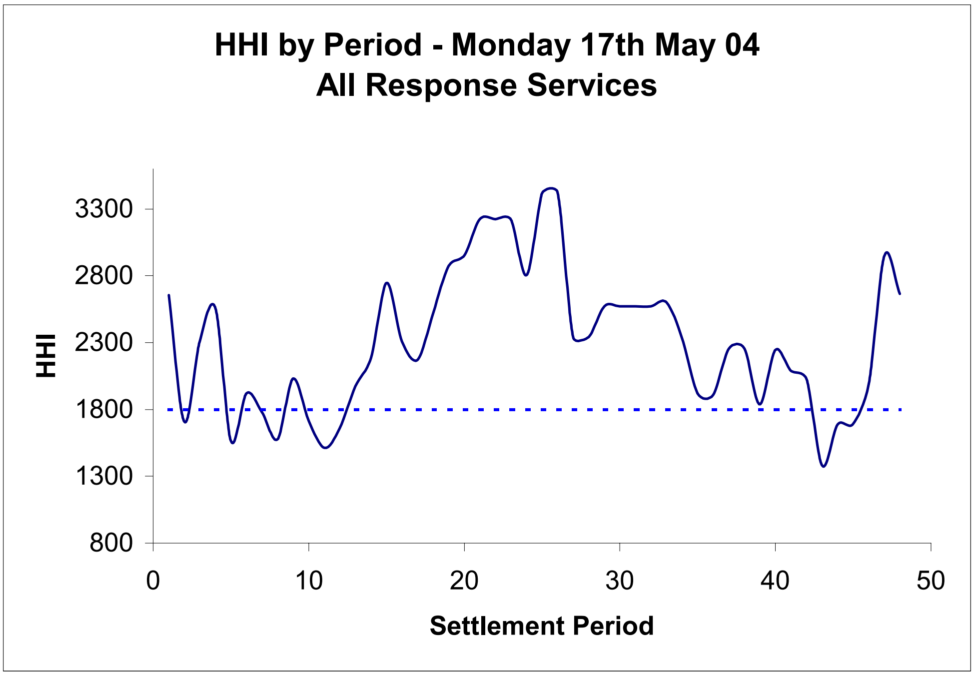
We have argued consistently during the development of CAP047 that we believe there are significant cost pressures, once the cost-reflective principle is lifted from Ancillary response. Indeed Ofgem, in its decision document, agree that CAP047 is likely to result in an increase in response cost. Following approval by Ofgem, CAP047 will be implemented from 1 October 2005, and so we will experience the upward cost pressure of CAP047 for the second half of the year 2005/06.

However, there are significant uncertainties surrounding the magnitude of the increase. In developing our forecast of the cost increase, we have considered a number of factors and different forecasting methods. They include

- Analysis of response market share/competition
- Past experience of introduction of new market
- Accepted bid prices in the BM. This is a market which, in theory, should reflect underlying fuel costs. It has a similar pricing principle as the new Response market

Our market share/competition analysis shows that, on an *annual* basis the response market appears to be competitive, with a Hirschmann-Hirfindahl Index of 1338. However, the response market is *half hourly*, and on the half hourly basis, there are significant market concentrations in certain periods of the day. This is illustrated by the half hourly HHI for Saturday 1st May 2004 and Monday 17th May 2004:





It can be seen from the above that for these two days there was significant market concentration for daytime periods with HHI well above 1800[100]. In particular, on Monday 17 May 2004, HHI for the period of 10am – 1pm is over 2800, implying that the response services were dominated by two or three service providers.

In addition, we estimate that on a annual basis there are more than 25% of half hourly settlement periods where less than 150% of our response requirement is readily accessible from gensets loaded on bars, suggesting little competition in these periods.

In order to assess the likely impact of the introduction of a market in response provision, we have looked at the development of a comparable market. Bid prices in the BM, in theory, should reflect generators' marginal cost, and are free to vary under NETA. This is similar to the proposed response market. In addition, the market share analysis shows that the HHI for bids accepted in the first six months of NETA is 1368, again, similar to that for the response market. Therefore, the analysis of bid price performance can be used to inform the forecast of the impact of the new response market.

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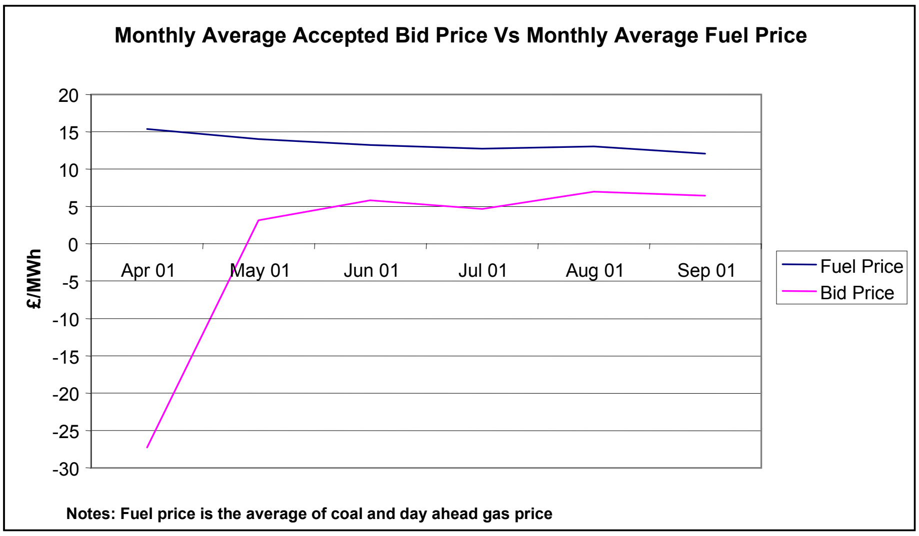
[100] In Ofgem's decision document on CAP047, a HHI of 1800 was used as an indicator of the degree of concentration in a market.

The graph below shows the monthly average accepted bid price and the average fuel price[101].



It can be seen from the above that over the first six months of NETA, the average Bid price is £0/MWh, whereas the average fuel price is £13.60/MWh. Even after the first six months, bid prices remained at a level equivalent to only 50% of fuel prices, i.e. a premium of 100%.

The prices and requirements in the response market will be transparent to providers, and so monthly submitted prices are likely to rise to the marginal price published for the previous month.

The implementation of the response market may encourage NGT to seek more commercial response providers, as indicated in Ofgem's decision document. If this can be achieved, it will increase our security of response provision but is unlikely to achieve significant savings, as all commercial contracts are likely to be priced to equivalent mandatory providers.

In summary, our analysis shows that the response holding prices are likely to increase significantly following the implementation of CAP047. We have taken a conservative approach, assuming reasonable market behaviours, and conclude that, on balance, the average response holding prices, including mandatory and commercial prices will rise by 50% from the implementation of CAP047. Our analysis

[101] Fuel price is the average of spot coal price (converted at an average efficiency rate of 38%) and day ahead NBP gas price (at an average efficiency rate of 49.13%)

of the development of the bid market has shown the existence of a precedent for a premium of 50% or more above cost reflective levels, in a market which appears to contain a similar level, if not more, competition than a response market. The costs of Ancillary response thus increase by £14.7m. In reality, we expect some prices to increase by less than 50%, and some by more than 50%.

B8. Constraints Forecast

As part of developing a GB constraint forecast, we have approached, through Ofgem, SPTL and SHETL, requesting information relating to their respective networks on the level of existing and future generation, planned transmission and generation outages, planned network reinforcement, and historical generator output. The information provided by SPTL and SHETL, together with their Seven Year Statements (SYS), forms the basis of our forecast.

Assumptions

In producing constraint forecasts, we have made certain assumptions about the GB transmission network, especially in Scotland. The main assumptions are briefly described below:

- The constraint across the Cheviot boundary (which is made up of the pre BETTA Anglo-Scottish interconnector circuits) is stability/thermal, with winter limits of 2200MW, and summer limits of 2000MW under intact conditions and 1200MW under outage conditions;
- There are 14 weeks of planned outages in 2005/06 across the Cheviot boundary, of which 10 weeks are associated with reconductoring works on the eastern circuits to accommodate the increased level of renewable generation in Scotland;
- Transmission limits within SPTL and SHETL networks are based on those contained in SPTL's April 2004 SYS and SHETL's 2003 SYS;
- The existing operational intertrip schemes within Scotland will continue to be available under BETTA; (e.g. the Ayrshire operational intertrip scheme and the Foyers stability intertrip scheme);
- No intertrip scheme is available for the Cheviot boundary;
- Where possible, the GBSO will be able to move planned outages in Scotland. The costs of shifting such outages are not included in the forecast, but are borne under a different scheme.

We have not considered the cost of the following issues in our forecast:

- Islanding Events
  In Highlands and Islands areas, such as the Western Isles, where part of the network is separated from the main interconnected system following a fault or under planned outage conditions, an embedded generator is traditionally required

to run to maintain local supply. It is not currently clear who will be responsible for these costs, and so no cost has been assumed in the forecast.

- Customer choice connections and different connection boundaries
  Where generator transformers are owned by the TO rather than the generator, or where a generator's connection is of customer choice[102], it is assumed that users' bilateral agreements will stipulate that such generators are not eligible for constraint payments in the event of a failure of the generator transformer or the customer choice connection.

- Local intertrip schemes
  Where local intertrip schemes are required to maintain local system security and integrity, any payments required to maintain them have not been considered in this forecast.

- Special treatment of non BMU embedded stations
  Where non-BMU embedded generation is required to maintain local security or local supply under outage conditions, it is not clear who will be responsible for these costs, and so no cost has been assumed in the forecast.

Clearly, should the GBSO, through the Balancing Services Incentive Scheme, be exposed to any costs resulting from the issues described above, the forecast of incentivised balancing costs would need to be amended.

Generation Background

Based on the information available to us, there are neither closures of existing generation, nor commissioning of new generation, other than new windfarms, in the GB market in 2005/06.

There are significant uncertainties about the number of windfarm projects commissioning in Scotland in 2005/06. We carefully considered each windfarm project as provided by SHETL and SPTL in terms of its likelihood of commissioning in 2005/06. As a result, we estimate that a total of 1400MW of windfarms will be commissioned by winter 2005. This is lower than the figure used by RETS and SKM

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[102] Connectees to the transmission system have an option to request a lower standard of connection. In Scotland, some generating stations have a connection to the transmission system, which is below that which would normally be offered to an applicant to connect to the transmission system. The term "customer choice" is used in the context of this appendix to refer to connections, which have a lower standard of security than would normally be offered to a user.

studies[103], and also significantly lower than that contained in the interim GB SYS (1800MW)[104]. We have assumed that the average load factor of wind generation is 35%. This is in line with the figure used by DTI and SKM studies.

Constraint Forecasting Approach

Due to the GB transmission network topology and the nature of constraints identified, we divide the GB transmission system into three parts and forecast their constraint costs separately. They are

- England & Wales
- Cheviot boundary
- Within Scotland

A consistent approach is used to forecast constraint costs in England & Wales and within Scotland. This is a bottom-up approach involving detailed studies of the transmission network, based on planned transmission and generator outages, and utilisation of short term circuit ratings and operational measures. Uncertainties in market participants' behaviours, such as French interconnector flows are studied and the impact estimated. Key outages and/or transmission groups/boundaries that cause significant constraint costs are identified, taking into account mitigating measures that may be available in operating time scales, such as shifting or shortening of outages. The risk and impact of plant closures are studied and estimated. All constraint forecasts are reviewed and challenged by experts within NGT, including those working in BETTA transition and implementation teams.

Forecasting Constraint Costs across the Cheviot Boundary

Under BETTA, Scottish generators will no longer be subject to the current administered interconnector arrangement and will be free to vary their output and operating regimes. This, coupled with the recent change of ownership for a large

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[103] The RETS studies were carried out by the three transmission companies to develop plans for network reinforcement to accommodate the connection of new renewable generation in Scotland. The SKM study was carried out by SKM on behalf of Ofgem as part of Ofgem's consideration of the plans of the three transmission companies.
[104] Wind capacity in the Interim GB SYS includes projects that are under construction, signed, and unsigned. The difference with the figure used in this study is primarily caused by the treatment of unsigned offers.

amount of E&W generation (in excess of 7.5GW) and the termination of the Scottish Nuclear Agreement from April 2005, makes it likely that there will be a significant change in the patterns and level of flows across the Cheviot boundary. We estimate that the impact of Carbon trading is unlikely to be great enough to have a major adverse impact on generator output in Scotland due to low Carbon costs (currently around €8 /tCO2e). In addition, the Cheviot boundary constraint is active and well known by market participants, being the subject of a number of studies and Ofgem consultations.

Therefore, there are great uncertainties surrounding the likely constraint costs across the Cheviot boundary primarily due to uncertainties in generator output in Scotland.

In order to estimate the constraint costs across the Cheviot boundary, we have developed a spreadsheet based annual probabilistic model. It models 11 demand blocks representing the Scottish demand duration curve, as contained in SPTL and SHETL SYS. Assuming reasonable generator behaviours, we forecast unconstrained Scottish station output by demand block and by scenario. The uncertainties in forecast station output and demand within each scenario are input into the probabilistic model.

The table below summarises forecast unconstrained Scottish generator output.

Station	Base	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5	Scenario 6	Mean
Nuclear	17	16.8	16.8	16.8	16.8	16.8	16.8	16.8
Thermal	20.9	20.0	22.1	26.1	20.9	18.4	22.4	21.4
Hydro	2.7	2.5	2.5	2.5	2.5	2.5	2.5	2.5
Wind	0.7	3.9	3.9	3.9	3.9	3.9	3.9	3.9

Notes: Base = August 03 – July 04

Wind output for the base period is estimated from actual transfer from Scotland to England.

The mean forecast output of conventional thermal power stations in Scotland shows little change from the historical level, although it varies from 18TWh in Scenario 5 to 26TWh in Scenario 3 reflecting scenario assumptions.

Constraint Prices

The Cheviot boundary mainly restricts flows from Scotland to England & Wales. Bid prices submitted by Scottish generators are an important factor determining the cost of constraints.

Assuming reasonable market behaviour, and based on historical actual submitted bid prices from SP and SSE, we estimate that bid prices will vary from approximately -£30/MWh to £15/MWh with appropriate probabilities. We further assume that a majority of the replacement energy (75%) can be sourced in the forward market, whilst the remaining 25% is sourced in the BM due to inherent uncertainties in generator output, especially wind. Therefore, the replacement energy price varies from scenario to scenario.

Results of Cheviot Constraint Cost Forecast

The table below summarises the forecast constraint costs across the Cheviot boundary:

Summary of Forecast Constraint Costs Across Cheviot Boundary (£m)

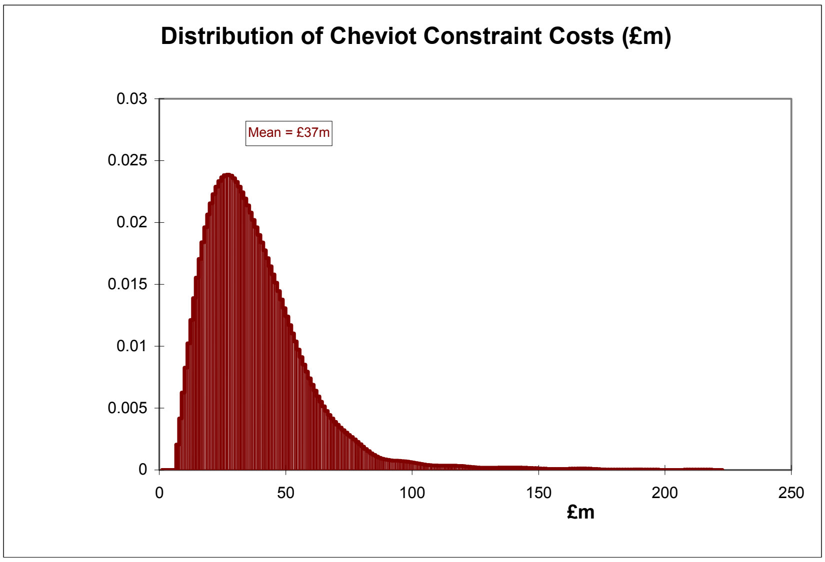
2005/06	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5	Scenario 6	Mean
Scenario Probability	10%	20%	10%	30%	15%	15%	
Mean Unconstrained Transfer (TWh)	7.08	9.01	12.88	7.93	5.67	9.45	8.45
Constraints							
Mean Volume (TWh)	0.98	1.56	2.10	1.14	0.81	1.03	1.24
Mean Cost (£m)	23.2	44.6	50.9	36.0	30.1	35.2	36.9

It can be seen that:

- The constraint volume varies from 0.81TWh to 2.1TWh with a mean of 1.24TWh. This is comparable to other studies, such as RETS and SKM studies. For example, SKM studies estimated that at a wind capacity of 1400MW the constraint volume was 1.34TWh.

• The mean constraint cost is £36.9m and varies from scenario to scenario due to different forward and BM prices, with a range of £23m in Scenario 1 to £51m in Scenario 3.

The graph below shows the distribution of forecast constraint costs across the Cheviot boundary. The forecast constraint cost is highly uncertain and ranges from £0m to £222m.



Constraint Costs within Scotland

At present, Scottish Power and Scottish Hydro Electric are vertically integrated companies, who own and operate transmission, distribution and generation. System constraint costs can be "planned out" through a co-ordinated and integrated planning process, or internalised between generation and transmission accounts. This is similar to the CEGB system before 1990. Under the new market arrangements, a significant amount of these constraint costs will be revealed. For example, following Vesting, constraint costs on the NGC system quickly escalated to over £250m in 1993/94.

Based on information provided by SHETL and SPTL, and their respective Seven-Year Statements, we carried out detailed annual system studies using our established constraint forecasting methodology. We estimate constraint costs within Scotland to be £17m. This equates to about 7% of the maximum of constraint costs experienced on the NGC system. This appears to be relatively low, given the fact that, as discussed previously, the volume of Scottish demand and generation is of the order of 12-16% of the volumes in England and Wales, and the Scottish transmission system is about 40% the size of that in England & Wales. Constraints in Scotland are mainly localised and therefore are not considered to vary by scenario.

Constraint Costs in England and Wales

The volatility of flows across the Anglo-French interconnector is a major factor influencing constraint costs in England & Wales. Based on detailed weekly system studies and market/generation intelligence, we estimate constraint costs in England & Wales to be £20m. The table below summarises the forecast constraint costs by major system area/boundary and by scenario.

Forecast E&W Constraints (£m)

2005/06 Scenarios									
Area/Boundary	**2003/04**	**2004/05**	**1**	**2**	**3**	**4**	**5**	**6**	**Mean**
North	4	5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
South	24	11	18	13	18	13	13	13	14
Flow South	4	2	3.5	3.5	3.5	3.5	3.5	3.5	3.5
Total	32	18	24	19	24	19	19	19	20

The reduction of constraint costs from £32m in 2003/04 to an estimated £20m in 2005/06 is primarily caused by a step change in French interconnector flows due to rising forward electricity prices in England & Wales.

Summary of GB Constraint Forecast

The table below summarises forecast GB constraint costs.

Summary of GB Constraint Costs (£m)

2005/06 Scenarios							
	1	**2**	**3**	**4**	**5**	**6**	**Mean**

England and Wales	24.0	19.0	24.0	19.0	19.0	19.0	20.0
Cheviot Boundary	23.2	44.6	50.9	36.0	30.1	35.2	36.9
Within Scotland	17.0						17.0
GB Total	64.2	80.6	91.9	72.0	66.1	71.2	73.9

In summary, we forecast a mean GB constraint cost of £73.9m with a range of £64m in Scenario 1 to £92m in Scenario 3. This is based on the mean forecast costs of Cheviot boundary constraints for each scenario. On a probabilistic distribution basis, the GB constraint cost has a much wider range, which contributes to the forecast GB IBC distribution as shown in section B11.

Constraint costs in Scotland and across the Cheviot boundary are uncertain. We have taken a conservative approach, assuming reasonable market behaviours. Although we have 10 years of experience in managing constraint costs in England & Wales, including 4 years under NETA, and have reduced constraint costs by over £200m, we have no experience or data in Scottish constraint management. Many effective constraint management tools and controls used to manage constraint costs in England and Wales will not be available in Scotland, at least not in the first year of BETTA.

B9. Transmission Losses Forecast

Methodology

GB transmission losses are forecast through a natural extension of our existing England & Wales transmission losses (TL) model. The basis of the model is forecast changes in zonal disposition of generation, since our observations of past years suggest that this is the most significant driver of losses volumes.

The difference between historical and forecast station output for each zone is multiplied by the Transmission Loss Factor to give the forecast change in zonal TL.

Forecast TL is calculated as base period TL plus the sum of forecast zonal TL changes. The total forecast Transmission Loss Adjustment (TLA) then equals the product of forecast TL and the reference price TLRP (assumed for the purposes of this forecast to be £21/MWh, as in 2004/05).

The base period is 2003/04, when England & Wales losses totalled 4.51TWh and Scottish losses were 1.08TWh (SP 0.664TWh and SSE 0.417TWh, as supplied by the Scottish companies). This gives a GB total of 5.59TWh for 2003/04.

Forecast

The table below shows the mean forecast losses volume in TWh for 2005/06. GB and Scottish loss volumes for 2003/04 and 2004/05 are also shown.

GB Transmission Losses (TWh)

	2003/04 outturn	**2004/05 projection**	**2005/06 mean forecast**
England and Wales	4.51	4.52	4.59
Scotland	1.08	1.09	1.24
GB	**5.59**	**5.62**	**5.83**

The mean forecast TLA for 2005/06 is £122.5m (i.e. 5.83TWh x £21/MWh).

The mean forecast GB TL for 2005/06 is some 4% (0.21TWh) higher than our projection for 2004/05. This is mainly due to the forecast increase of Scottish wind generation.

Our scenario-based approach allows us to model the significant uncertainty in GB TL volumes, which arises from the forecast variability in:

- Scottish generation
- Transfers across the Anglo-French Link
- Generation in England & Wales.

Across scenarios, forecast GB TL is 5.67-6.14TWh (mean 5.83TWh) and TLA £119.1-128.9m (mean £122.5m). We assume that losses follow a normal distribution, with a standard deviation of 0.15TWh (£3.15m).

B10. Balancing Mechanism plus Trades Forecast

NGC's pre-gate trading activities strongly interact with balancing actions in the BM, as forward trades can directly substitute for BM actions. As a result, these two aspects of balancing actions are considered together in an integrated IBMC+Trade model.

The model is a scenario based extrapolation approach, representing the whole year with 36 time periods (3 seasons, 2-day types, and 6 EFA blocks). Historical outturn data for the base period are broken down and processed into an appropriate format in each time period. The model takes into account the scenario assumptions and parameters, and calculates the appropriate amount of pre- and post-gate balancing actions according to the risk profiles and NGC's operating requirements. For example, the amount of pre-gate energy trades is a function of forecast market length (NIV), price spread between the forward market and the BM, and NGC's risk profile and risk management policy.

The table below summarises the forecast costs of IBMC+Trade by scenarios.

Summary of Forecast IBMC' + Trade' Costs by Scenario (Excluding Constraints) (£m)

	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5	Scenario 6	Mean
NIA	-16.6	4.2	-42.0	-10.5	43.4	23.9	1.9
BMC'	62.3	91.2	34.6	81.7	131.4	121.8	90.4
Trading'	-3.8	0.1	-8.2	-0.2	9.9	7.2	1.3
IBMC'	78.9	87.0	76.6	92.2	88.0	97.9	88.5
IBMC' + Trade'	**75.1**	**87.1**	**68.4**	**92.0**	**97.9**	**105.1**	**89.8**

As mentioned above, NIA, BMC' and Trade' directly interact with each other and are quite volatile from scenario to scenario. For example, NIA varies from -£42m in Scenario 3 to £43m in Scenario 5 primarily caused by changes in scenario market lengths and forward prices. Therefore, it is generally not useful to consider them in isolation.

The mean forecast cost of IBMC'+Trade' (excluding constraints) is £89.8m with a range of £68.4m in Scenario 3 to £105.1m in Scenario 6.

In general, the cost of IBMC'+Trade' is a function of the scenario drivers as detailed in section B4. For example, Scenario 3 has the lowest forecast cost of IBMC'+Trade' due to assumed high level of competition in the forward market and the BM. Low forward and competitive BM prices reduce the cost of trades and BM actions, whilst a high level of free headroom and plant margin require fewer system actions for margin purposes. Similarly, high forward and BM prices in scenario 6 increase the cost of trades and margin actions. Low free headroom and plant margin require a high level of system actions for margin purposes. Therefore, the cost of IBMC'+Trade' in this scenario is the highest at £105m.

B11. Total IBC Forecast and Distribution

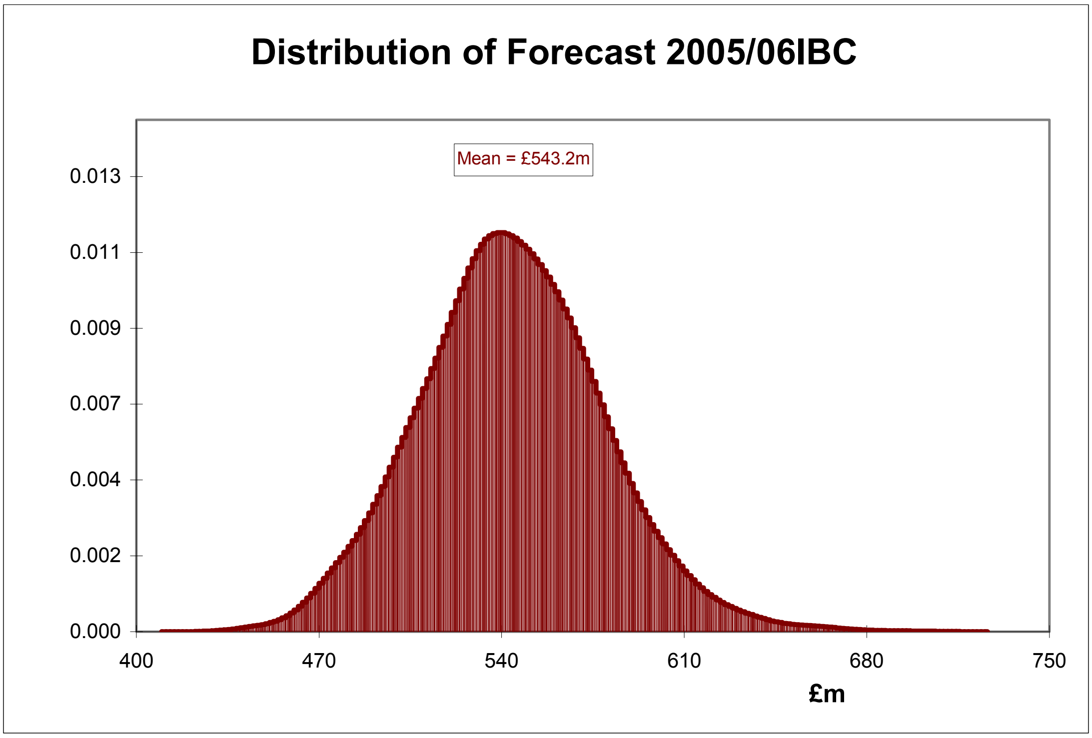
Our total forecast of IBC, aggregating the categories discussed in sections B6 to B10, is shown in the table below.

Summary of Forecast Scenario Costs for 2005/06 (£m)

	Scenario 1	**Scenario 2**	**Scenario 3**	**Scenario 4**	**Scenario 5**	**Scenario 6**	**Mean**
IBMC + trading less constraints	75.1	87.1	68.4	92.0	97.9	105.1	89.8
AS less constraints	247.1	250.8	241.4	258.7	269.6	265.6	256.9
Transmission Losses	120.8	122.9	128.9	121.8	119.1	123.9	122.5
Constraints	64.2	80.6	91.9	72.0	66.1	71.2	73.9
IBC	**507.3**	**541.4**	**530.5**	**544.5**	**552.6**	**565.8**	**543.2**

It can be seen that IBC varies from £507m in scenario 1 to £566m in scenario 6. The probability-weighted mean forecast is £543.2m.

There are significant uncertainties surrounding the forecast scenario cost due to the stochastic nature of IBC components. These uncertainties are captured through Monte Carlo simulation of forecast scenario IBC components whose standard deviations are derived from historical volatility. The resulting scenario distributions are combined to give the overall distribution of forecast GB IBC. This is shown below.



The distribution is slightly skewed, and shows a significant range from a 5th percentile at £487m to a 95th percentile at £600m. The standard deviation of our forecast is £35m.

B12. Comparisons with Previous Years

The table below compares the forecast IBC for 2005/06 with historical outturn IBC in E&W since NETA "go-live". For consistency, the outturns are shown in the same format as the forecast.[105]

Comparison of Forecasts with Historical Outturn.

	2001/02	2002/03	2003/04	2004/05	2005/06	Variance to 04/05
IBMC + trading less constraints	94.6	75.6	71.0	82.0	89.8	7.8

[105] Constraint costs cannot be exactly calculated for previous year's outturn. However, NGC can estimate the cost for the purpose of analysing balancing costs.

AS less constraints	169.9	199.9	177.5	199.9	256.9	57.0
Transmission Losses	91.5	80.8	76.6	95.0	122.5	27.5
Constraints	9.3	28.0	31.6	18.0	73.9	55.9
IBC	**365.3 (E&W)**	**384.3 (E&W)**	**356.8 (E&W)**	**394.9 (E&W)**	**543.2 (GB)**	**148.2**

Of course, costs for previous years are on an England & Wales basis, whereas the forecast for 2005/6 is on a Great Britain basis. The impact of this is discussed in the following section.

B13. Consideration of Forecast

The mean forecast of £543m for 2005/6 is considerably greater than the cost of IBC experienced in England & Wales, and £148m above our projection of £395m for E&W in 2004/5. As discussed in the previous sections, there are many factors driving this increase. For discussion purposes, we group them into the following categories

- Moving to a GB Market, cost changes due to revelation of existing TO activities in Scotland
- Scottish Constraints
- Cost Pressures on Existing Activities, costs changes in on-going activities

It should be noted that it is not possible to accurately split the forecast cost into the above categories since our forecast is based on a GB wide market. The allocation of the forecast costs into the above categories is subjective and should be considered in the context of comparison analysis.

Moving to a GB Market £61m

All balancing services on a GB basis see a requirement for an increase in volume, compared with the current E&W basis. Within the cost categories of Reactive, Response, Footroom, all Reserve, and Black Start, we forecast an additional cost of £34m due to this additional volume alone. This increase equates to 12% of the equivalent projected cost within E&W for 2004/05, and this is in line with the broad metrics that Scottish demand represents an 11% increase on E&W, and Scottish generation represents a 14-16% increase on E&W.

IBC includes a cost of Transmission Losses, and our forecast cost of Transmission Losses shows an increase of £27m. We have used a constant reference price (TLRP) of £21/MWh, and so this increase mainly reflects the forecast of Scottish transmission losses, as described in section B9.

These costs do not represent an incremental cost as a result of the implementation of BETTA. SSE and SP already carry out these services, but their costs are currently internalised. BETTA merely reveals them explicitly within GB IBC.

Scottish Constraints £54m

The costs of both £37m for constraints across the Cheviot boundary and £17m for within-Scotland constraints are currently internalised within the Scottish companies. BETTA reveals these costs explicitly within GB IBC.

The flow across the current Anglo-Scottish interconnector is administered, such that Scottish Power and SSE, who own almost all the Interconnector Capability, are not permitted to declare a flow above the capability. Thus the volume of potential constraint is never revealed, and is internalised within the Scottish companies. An equivalent situation arises for the volume of within-Scotland constraints.

Nonetheless, the constraints currently restrict the free operation of Scottish generation, and the internalised cost, to the extent that Scottish companies consider it, is on the basis of fuel prices. Post-BETTA, the price of Scottish constraints will be subject to commercial bid and offer prices, freely declared by the Scottish companies. These constraint prices will be subject only to what competition exists for each individual constraint.

Cost Pressures on Existing Activities £33m

The remaining £33m of cost increases arise from cost pressures on existing activities. These include:

Reactive £9m: the price of Reactive, following the CAP045 indexation to Power Exchange prices, is expected to increase markedly, in line with current forward prices.

CAP047 £15m: the removal of the cost-reflective principle for the pricing of Ancillary response is acknowledged by Ofgem as likely to cause a short-term increase in the costs of Response. We have argued throughout debates on CAP047, repeated above, that this effect is likely to amount to £15m for the first six months of implementation.

Reserve/Margin £13m: the volume of actions required for Reserve/Margin is increasing, in line with the trend of decline in Free Headroom. The advent of Scottish providers will at best contain the current trend of price increases for these services, and even this relies on Cheviot constraints not too often restricting Scottish reserve provision.

E&W Constraints £2m: the current year 2004/5 is proving to be a low-cost year for E&W constraints at £18m, mainly because of low flows from England to France. For 2005/6, we forecast a small increase of £2m.

Others, including Energy Balancing –£6m: across the remainder of our forecast, there are some modest downward cost pressures. The largest of these is that the combination of a naturally longer market post-BETTA, and rising Bid prices in line with higher fuel prices, causes a £6m decline in the net costs of Energy Balancing.

Overall Consideration

So, of the three categories of cost increases, the two largest increases arise from the transition to BETTA, and merely reveal costs that are currently internalised within SSE and SP. The third category of cost increase mainly reflects the impact of CUSC modifications recently approved.

B14. Conclusion

There exist significant uncertainties and challenges in forecasting GB IBC for 2005/06. We believe that the bottom-up, scenario based extrapolation approach we have adopted is a robust and sensible method. It allows us to identify many underlying cost drivers whilst at the same time enables us to forecast IBC on a GB basis, assuming reasonable market behaviours.

Although moving to a GB market may increase competition in some areas of system balancing, it will reveal the true cost of balancing activities that are currently carried out by SHETL and SPTL, which are internalised. We forecast this cost to be £61m in total, including £27m in transmission losses and £34m in system balancing activities. The cost of £34m in system balancing activities represents 11% of equivalent costs in E&W for 2004/05. This is reasonable considering that the total Scottish generation is about 14-16% of E&W, and balancing costs are primarily driven by generation.

Similarly, the implementation of BETTA will reveal the true extent of constraints within SPTL and SHETL transmission systems and across the Cheviot boundary. These costs are currently internalised within SPTL and SHETL and suppressed by the present administered Anglo-Scottish interconnector agreement. Based on the detailed studies and our conservative approach, we estimate that these constraint costs to be £54m, including £17m within SHETL and SPTL transmission systems and £37m across the Cheviot boundaries.

In addition, we have identified a number of cost pressures on the existing activities. They include the implementation of CAP047, continued reductions of free headroom, and rising forward electricity prices. These developments will increase the balancing costs by £33m from the equivalent costs for E&W in 2004/05. This is considered reasonable, since the effect of CAP047 and CAP045, both direct results of approved CUSC modifications, totals £24m. The remaining balancing activities see an increase of only £9m, which represents an increase of about 3%.

In summary, we have presented in this appendix the basis of our forecast of £543m for GB IBC in 2005/6. We believe that the assumptions and derivation of this forecast are all reasonable.