

Potential income adjusting events under NGET's 2005/06 system operator incentive scheme

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Target audience: This document will be of interest to electricity generators, suppliers, customers and other interested parties.

Overview:

National Grid Electricity Transmission plc (NGET) is the system operator (SO) for the electricity transmission system in Great Britain (GB), and is required to act in an efficient, economic and co-ordinated manner in performing this function. To encourage this, each year we develop a SO incentive scheme with specific cost targets, but we allow proposed income adjusting events (IAEs) to be raised.

On 30 June 2006, NGET submitted notices of two proposed IAEs relating to its 2005/06 SO incentive scheme, for additional costs it says it incurred in managing transmission constraints within Scotland and between Scotland and England, and in procuring frequency response following CUSC Amendment Proposal 047.

This document outlines our initial views on each of these two proposed IAEs, and invites feedback from interested parties on a number of questions set out in this document.

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Context

National Grid Electricity Transmission plc (NGET) is the system operator (SO) for the electricity transmission system in Great Britain (GB), with responsibility for making sure that electricity supply and demand stay in balance and the system remains within safe technical and operating limits. NGET is required to act in an efficient, economic and co-ordinated manner in performing this function, and to encourage this, each year we develop an SO incentive scheme with specific cost targets. However, NGET is allowed to submit notices to Ofgem¹ of proposed income adjusting events (IAEs) if costs (or savings) are incurred in connection with its SO activities that were not envisaged at the time that the cost target was agreed.

In 2005/06, NGET's SO incentive scheme had a cost target of £377.5 million. On 30 June 2006, NGET submitted notices to us of two proposed IAEs relating to its 2005/06 SO incentive scheme. NGET is asking for a total reduction of £35.77 million in its 2005/06 balancing costs of £427.2 million to reflect additional costs it says it incurred separately in managing transmission constraints within Scotland (£18.54 million) and between Scotland and England (£11.63 million), and in procuring frequency response following CUSC Amendment Proposal 047 (£5.59 million).

This document summarises each of NGET's notices, outlines our initial views, and invites feedback from interested parties on a number of questions set out in this document.

Associated Documents

- NGET's [Notice of proposed income adjusting events under the 2005/06 system operator incentive scheme](http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/15623_ofgem_300606.pdf?wtfrom=/ofgem/whats-new/archive.jsp) (Reference 111/06).
http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/15623_ofgem_300606.pdf?wtfrom=/ofgem/whats-new/archive.jsp
- Ofgem's Final Proposals and statutory licence consultation: NGC System Operator incentive scheme from April 2005; February 2005 (Reference 65/05).
http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/10404_6505.pdf?wtfrom=/ofgem/whats-new/archive.jsp
- Ofgem's Connection and Use of System Code Proposed Amendment CAP047: "Introduction of a competitive process for the provision of mandatory frequency response" Impact Assessment, August 2004, (reference 210/04).
http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/8441_cap047ia_fin_al.pdf?wtfrom=/ofgem/whats-new/archive.jsp

¹ The role of Ofgem in supporting the Authority is described in the appendices. Any final decision will (as a matter of law) be that of the Authority; in practice decisions may be taken under delegated authority.

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Summary

The purpose of this document is to invite views from interested parties on two proposed income adjusting events (IAEs) submitted by National Grid Electricity Transmission plc (NGET).² The proposed IAEs relate firstly to transmission system constraints within Scotland and between Scotland and England (the Cheviot constraint), and, secondly, to the procurement of frequency response following the implementation of CUSC Amendment Proposal 047 (CAP047).

Background

NGET is the system operator (SO) for the high voltage electricity transmission system in Great Britain (GB), with responsibility for making sure that electricity supply and demand stay in balance and the system remains within safe technical and operating limits.³ NGET's transmission licence requires it to act in an efficient, economic and co-ordinated manner in performing this function.

Each year, we develop an SO incentive scheme, which is designed to encourage NGET to operate the GB transmission system in an efficient and economic manner, and to reduce the costs of operating the system. These costs are borne by transmission system users and, ultimately, by electricity consumers. The SO incentive scheme establishes a target for the costs that NGET incurs in performing its SO role. If actual costs are below the target, NGET is permitted to retain a proportion of the savings, while if actual costs exceed the target, NGET bears a proportion of the excess costs.

The scheme also allows NGET, in prescribed circumstances, to submit notices to us of proposed IAEs, where costs are incurred in performing its SO role in connection with events that were not envisaged at the time that the cost target was agreed.⁴

The 2005/06 SO incentive scheme for the first time covered NGET's GB wide system operator costs, since the British Electricity Trading and Transmission Arrangements (BETTA) were implemented on 1 April 2005. Previously, NGET had only been the SO for the England and Wales transmission system. The target was set at £377.5 million, and the cap and floor were +£40 million and -£20 million with upside and downside sharing factors of 40% and 20% respectively.

One result of the implementation of BETTA was that NGET became responsible for the management of transmission constraints within Scotland. These had previously been the responsibility of the vertically integrated Scottish electricity companies.

² Separate notices relating to each IAE were submitted to us by NGET on 30 June 2006.

³ Note that National Grid Gas plc, another subsidiary of National Grid the parent company of NGET, is the system operator and transmission asset owner for the gas transmission system in GB, by virtue of holding the gas transporter licence in respect of the National Transmission System.

⁴ The licence also provides for NGET, and BSC and CUSC parties, to submit notices to us where there have been savings in relation to events that were not envisaged at the time that the cost target was agreed.

Further, from November 2005 there was a change to the manner in which prices for frequency response were determined⁵. This service is procured from both generators and large customers to maintain frequency on the transmission system within prescribed limits. We agreed to include allowances within the 2005/06 incentive target for both these changes to NGET's balancing costs.

Proposed income adjusting events

On 30 June 2006, NGET submitted notices to us of two proposed IAEs, asking for a total reduction of £35.77 million to its actual 2005/06 incentivised balancing costs of £427.2 million, made up of:

- £30.18 million, which NGET says reflects the amount by which the actual cost of managing within Scotland and Cheviot constraints exceeded the allowance included in the 2005/06 SO incentive scheme, comprised of
 - £18.54 million for within Scotland constraints,
 - £11.63 million for Cheviot constraint, and
- £5.59 million, which is the amount by which NGET claims the actual increase in frequency response procurement costs following CAP047 exceeded the allowance included in the 2005/06 SO incentive scheme.⁶

Ofgem's views

In this document, we raise a number of questions in relation to each of the proposed IAEs. In particular, for internal to Scotland and Cheviot constraint costs, we ask whether the events were foreseeable and whether NGET acted economically and efficiently. On the proposed CAP047 IAE, we are concerned whether the structure of the incentive scheme created perverse incentives on NGET and potentially on other participants. We also raise questions on NGET's costing methodology.

Our analysis of these questions, including responses to this consultation, will be used to assess whether NGET acted economically and efficiently with respect to each proposed IAE and if any adjustment should be made to the 2005/06 SO incentive scheme.

Next steps

For each notice of a proposed IAE submitted to us, we are required by virtue of NGET's transmission licence to separately determine whether it is an IAE within three months. We expect to publish our determination on each of NGET's proposed IAEs, including the amount of any allowed income adjustment, by 29 September 2006 after considering the views provided by interested parties to this consultation.

⁵ CUSC Amendment Proposal 047 (CAP047).

⁶ The non-confidential parts of NGET's notices were published on our website on 5 July 2006.

1. Introduction

Chapter summary

This chapter outlines the process we will follow in considering whether NGET has acted economically and efficiently in minimising costs incurred in connection with the proposed IAEs, and in determining whether any or all of its proposed income adjustment should be allowed. It also outlines the structure of the document and next steps.

Question box

There are no specific questions in this chapter.

Background

1.1. On 30 June 2006, NGET submitted notices to us of two proposed IAEs in respect of:

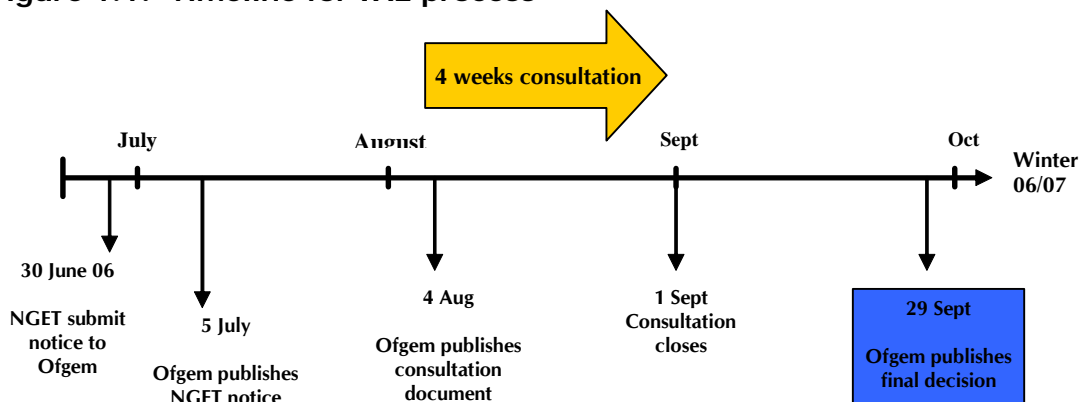
- management of within Scotland and Cheviot constraints (£18.54 million and £11.63 million respectively for a total of £30.18 million), and
- procurement of frequency response following the implementation of CUSC Amendment Proposal 047 (CAP047) (£5.59 million).

1.2. NGET's transmission licence requires that, once we have received notice of a proposed IAE, and after consultation with NGET and relevant parties, we must determine within three months:

- whether any or all of the costs and/or expenses given in a notice resulted from an IAE,
- whether the proposed IAE has increased (or decreased) NGET's costs by more than £2 million, and
- if so, whether the amount of the proposed income adjustment ensures that the financial position and performance of NGET is, insofar as is reasonably practicable, the same as if that IAE had not taken place, and if not, what allowed income adjustment would secure that effect.

1.3. Although we are consulting on both of NGET's proposed IAEs in this document, we will consider each independently, and make two separate final determinations. Interested parties may provide feedback to us on either or both of NGET's proposed IAEs. We would ask parties to make clear in their responses to which of the two proposed IAEs their comments apply.

1.4. The timeline we are following in making a determination with respect to each proposed IAE is set out in Figure 1.1 below.

Figure 1.1: Timeline for IAE process

1.5. In consulting on our initial views, we are providing 4 weeks for interested parties to provide their feedback to us, rather than the standard 6 weeks. We have reduced the consultation period as we would not otherwise be able to undertake our initial analysis, and then fully consider respondents' feedback to this paper while adhering to our internal processes for making a final determination within the permitted three months.

Structure and Approach

1.6. This consultation paper consists of five chapters. Chapter 1, outlines the process we will follow in considering whether NGET has acted economically and efficiently in minimising costs incurred in connection with the proposed IAEs, and in determining whether any or all of its proposed income adjustment should be allowed. It also outlines the structure of the document and next steps.

1.7. Chapter 2 provides a more detailed overview of the background of the objectives of SO incentive schemes and how they work, a summary of specific changes in market arrangements that impacted on the design of the 2005/06 SO incentive scheme, as well as details of the scheme target and NGET's actual performance. This chapter concludes with a high level overview of IAEs, including IAEs that have been submitted to us in the past by NGET, and our role now that we have received NGET's notices.

1.8. Chapter 3 outlines issues related to the management of internal to Scotland transmission constraints and the Cheviot constraint that we consider are relevant in determining whether NGET has acted economically and efficiently in minimising constraint costs, and so in determining whether any or all of its proposed income adjustment should be allowed.

1.9. Similarly, Chapter 4 summarises events related to the procurement of frequency response following the implementation of CAP047 that we consider are relevant in determining whether NGET has acted economically and efficiently in minimising

frequency response costs, and so in determining whether any or all of its proposed income adjustment should be allowed.

1.10. In Chapter 5 we briefly summarise our next steps.

Way Forward

1.11. We pose a series of questions with respect to each proposed IAE throughout this document on which we are particularly interested in gaining the views of interested parties. However, these should not be seen as exhaustive, and we are interested in respondents' views on any aspect of the events and circumstances related to either or both of the proposed IAEs outlined in this document.

1.12. Once again, we would ask that respondents make it clear in their responses to which of the two proposed IAEs their comments apply.

1.13. Responses should be sent to wholesale.markets@ofgem.gov.uk, to be received no later than **1 September 2006**. Further details of how to respond can be found in Appendix 1.

2. Background

Chapter summary

This chapter outlines the general nature of SO incentive schemes that have applied to NGET in its role in operating the GB transmission system, and specifically that which applied in 2005/06. It also provides background to IAEs, including the relevant licence provisions and previous IAEs that we have approved.

Question box

There are no specific questions in this chapter.

NGET's system operation role

2.1. From April 1990 to March 2005, NGET (and its predecessors) was the SO for the England and Wales high voltage electricity transmission system only. With the commencement of the British Electricity Trading and Transmission Arrangements (BETTA) on 1 April 2005, NGET became the SO for the GB transmission system, which now encompasses England, Wales and Scotland.⁷

2.2. As SO for the transmission system in GB, NGET is responsible for residual purchasing and selling of electricity to keep transmission system demand and supply in balance in real time ('energy balancing'). It is also responsible for ensuring the system remains within safe operating limits and that the pattern of generation and demand is consistent with any system transmission related constraints ('system balancing').

2.3. NGET has a variety of tools available to assist it in performing its energy and system balancing role, including: buying or selling electricity in the Balancing Mechanism (BM), and/or signing Balancing System Services Contracts (BSSC) with market participants for frequency response and reserve services.

2.4. Costs incurred by NGET in energy and system balancing are borne by transmission system users and, ultimately, by electricity consumers. As it is the sole provider of these services, and hence competitive pressures cannot assist in placing downward pressure on its costs, NGET's transmission licence obligates it to act in an efficient, economic and co-ordinated manner.

⁷ Note that NGET is owned by National Grid, which also owns National Grid Gas plc (NGG). NGG is another subsidiary of National Grid and is the system operator and transmission asset owner for the gas transmission system in GB, by virtue of holding the gas transporter licence in respect of the National Transmission System.

2.5. To encourage NGET to operate the GB transmission system in an efficient and economic manner, and to reduce the costs of operating the system, each year we develop an SO incentive scheme, which is discussed in the following section.

SO incentive schemes

2.6. Since 1996, we have typically set annual incentive schemes, of various forms, to encourage NGET (and its predecessors) to undertake its SO role in the most efficient and economic manner.⁸ These incentive schemes have been designed to encourage NGET to manage and reduce the costs of operating the transmission system in GB, and therefore the level of costs borne by transmission system users and ultimately by customers.

2.7. Typically, under such a scheme, NGET is set a target for the level of electricity and system balancing costs it should incur in its SO role, referred to as incentivised balancing costs (IBC).⁹ Appendix 2 provides a more detailed overview of the components of IBC.

2.8. If actual IBC is below the target, NGET retains a proportion, set by a sharing factor (the upside sharing factor), of the reduction in costs. If its costs are above the target, NGET incurs a proportion, set by a sharing factor (the downside sharing factor), of the costs in excess of the target. NGET's overall gains or losses on its balancing costs are limited by applying a **cap** on the profits and a **collar (or floor)** on the losses.

2.9. In setting IBC targets, sharing factors, and associated caps and floors, we aim to provide NGET with an appropriate balance of risk and reward that best serves the interests of transmission system users and, ultimately, electricity customers. To arrive at the final proposals for each incentive scheme, we generally:

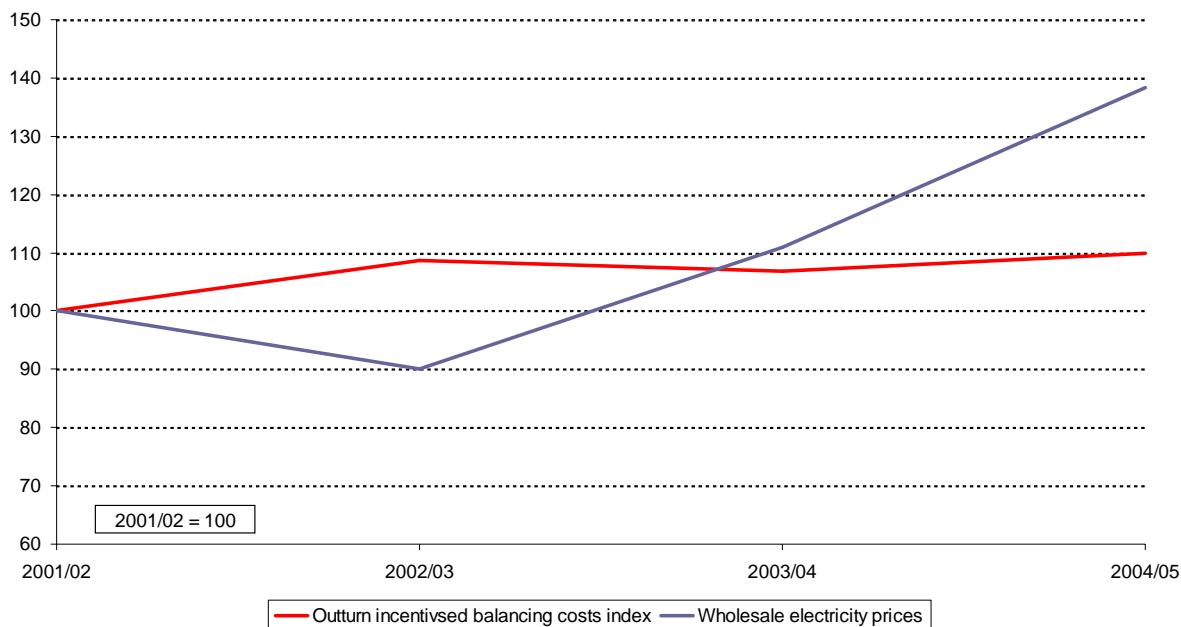
- consult on the broad scope and form of the incentive scheme, usually through an 'open letter'. NGET also submits its forecast of IBC for the following year and its projected costs for this year (based on its year-to-date costs) to us,
- on the basis of this data and feedback to our open letter, we then consult on an initial set of proposals for the new SO incentive scheme, and
- finally, in light of responses to this consultation and any updates that NGET may provide, we then produce a final proposals and statutory licence consultation, usually by the end of February, to ensure that the necessary licence modifications can be made for 1 April.

⁸ From 1994-1996 the incentive arrangements were set by suppliers. Between 1996 and 2001, the Office of Electricity Regulation set various incentive schemes that became BSIS from 2001 onwards. In the following sections we concentrate on the schemes that have been in place since the introduction of the New Electricity Trading Arrangements (NETA) on 1 April 2001.

⁹ The incentive schemes have also covered additional elements as well as balancing costs.

2.10. As shown in Figure 2.1 below, the effectiveness of the incentive schemes is reflected in the fact that for the first four years since the implementation of NETA, SO costs have increased by only 10 percent despite wholesale electricity prices increasing by nearly 40 percent. Both transmission system users (and ultimately electricity customers) and NGET have enjoyed the benefits of these reductions in relative costs as they have shared such cost reductions between them.

Figure 2.1: Index of wholesale market prices and IBC



2.11. However, this trend did not continue into 2005/06, when NGET's actual IBC exceeded the target for the first time. We consider the background to the development of the 2005/06 SO incentive scheme in the following section.

2005/06 SO incentive scheme

2.12. During the consultation process for the 2005/06 SO incentive scheme, the impact of two specific events was considered in detail. These were the commencement of BETTA and the implementation of CAP047. These are discussed further below.

2.13. The 2005/06 SO incentive scheme coincided with the implementation of BETTA on 1 April 2005. While NGET had previously been the SO for the England and Wales transmission system only, with the commencement of BETTA it also assumed the SO role for the Scottish transmission network, which had previously been the responsibility of the vertically integrated Scottish electricity utilities. That is, NGET would be responsible for the costs of energy and system balancing for the whole GB transmission system, which now included Scotland.

2.14. Before BETTA, the Scottish companies had undertaken system balancing actions to ensure the Scottish transmission system remained within safe operating limits and that the pattern of generation and demand was consistent with any transmission system related constraints through operational agreements.¹⁰ Similarly, the Cheviot constraint was also managed through operational agreements. The costs that NGET would incur in the market through system balancing actions to manage these constraints under BETTA were uncertain at the time the 2005/06 incentive parameters were set.

2.15. Further on 28 September 2004, we directed NGET to implement CAP047 from 1 October 2005, which was subsequently delayed until 1 November 2005. CAP047¹¹ removed the administered 'cost reflective' basis for setting Holding Payment prices within mandatory frequency response, which NGET uses to maintain the frequency of the transmission system within prescribed bands. Instead generators would be able to price freely this aspect of the service.

2.16. These two issues, and a lack of consensus on their likely impact on SO costs, created some uncertainty in establishing a cost target for the 2005/06 SO incentive scheme. Specifically:

- pre-BETTA, the cost of constraints within Scotland and the Cheviot constraint had been internalised by Scottish Power (SP) and Scottish and Southern Energy (SSE), and limited information was available on the economic and efficient cost of managing these constraints, and
- an increase in frequency response prices was expected in the short-term as a consequence of CAP047, although the extent of this potential increase was unclear.

2.17. NGET originally projected its IBC for 2005/06 would be £543.2 million, a £148 million increase over its forecast outturn of £394.9 million for England and Wales in 2004/05. This higher forecast reflected:

- £61 million in additional costs associated with energy balancing under BETTA,
- £56 million associated with the management of internal to Scotland transmission constraints (£17 million) and the Cheviot constraint (£36.9 million) (i.e. system balancing costs), and
- £31 million as a result of cost pressures on existing activities (including £15 million for the implementation of CAP047).

¹⁰ The details of transmission constraints within Scotland are discussed in more detail in chapter 3.

¹¹ The details of CAP047 are discussed in more detail in chapter 4.

2.18. The 2005/06 incentive scheme parameters set by us in our final proposals are summarised in Table 2.1 below.¹²

Table 2.1: 2005/06 SO external incentive scheme targets

Target (net of transmission losses) (£m)	Upside (bonus to NGET if costs are below target)		Downside (costs to NGET if costs are above target)	
	Sharing factor	Cap (£m)	Sharing factor	Floor (£m)
377.5	40%	40	-20%	-20

2.19. We agreed to include allowances in the target for within Scotland and Cheviot constraint costs, and the additional cost of frequency response following the implementation of CAP047, which are outlined in Table 2.2 below.

Table 2.2: Specific allowance within the 2005/06 SO incentive scheme target

Area	Allowance within target
Cheviot constraints	£20 million
Within Scotland constraints	£10 million
CAP047 costs	£7.35 million

2.20. At the time these allowances were determined, we noted that significant uncertainties existed regarding the expected level of costs in these two areas.

2.21. In our final proposals and statutory licence consultation document, we also noted that NGET's transmission licence would enable it to submit notice of a proposed IAE where there were material deviations, net of any countervailing factors, above or below these allowances. We also stated that material deviations away from these allowances would not necessarily constitute an IAE.

2.22. In our final proposals and statutory licence consultation document we noted the importance of market participants being kept informed of Scottish constraint costs, and the cost of frequency response following the implementation of CAP047. In this context, we note that NGET provided updates on these items to industry participants through the Operational Forum in February 2006 and June 2006.

¹² Note that the final IBC target in 2005/06 was established net of transmission losses. Under the previous gross treatment of transmission losses, the target IBC of £377.5 million equates to £500 million.

2.23. NGET has since calculated, in line with the requirements of its transmission licence and charging methodology statement, that actual IBC incurred in 2005/06 was £427 million, almost £50 million higher than the target of £377.5 million.

Income adjusting events

2.24. As noted above, the SO incentive scheme, which is set out in detail in its transmission licence¹³, provide for NGET, and other BSC and CUSC parties, to submit notices to us of proposed IAEs. Appendix 3 provides a more detailed overview of the relevant licence provisions relating to IAEs.

2.25. The IAE provisions are intended to provide protection for NGET and transmission system customers in case an event or set of circumstances occur that result in costs or savings to NGET in the performance of its SO function where the event or set of circumstances was not envisaged at the time that the IBC target was set.

2.26. Notice of a proposed IAE event, and the amount of any allowed income adjustment proposed as a consequence of that event, may be submitted to us up to three months after the close of the incentive scheme period.

Previous IAEs

2.27. NGET has previously submitted notices of two proposed IAEs in relation to events, or circumstances, that arose in its role as SO of the England and Wales transmission network before the introduction of BETTA.

2.28. The first related to the 2002/03 SO incentive scheme when NGET entered into a balancing services contract with AES Drax (Drax) following financial difficulties at TXU.¹⁴ NGET determined that there would be an unacceptable risk to security of supply if Drax were to be unavailable to the market or to NGET as a consequence of commercial contractual issues with TXU, and hence it sought to avoid this possibility through this contract.

2.29. The second proposed IAE was with respect to the 2003/04 SO incentive scheme, and related to a Supplemental Standing Reserve Tender (SSRT) that NGET conducted in October 2003. The SSRT was for the procurement of additional reserve services for winter 2003/04, and followed NGET requesting clarification from Ofgem

¹³ Refer to Special Condition (SC) AA5A part 2(i) of NGET transmission licence.

¹⁴ In November 2002, a number of issues arose as a consequence of the financial difficulties that TXU Europe faced which ultimately resulted in the company entering into administration. Drax was one of a number of counterparties which had a contractual relationship with TXU Europe. Drax is a 4GW coal-fired power station which represented 6.6 per cent of total generation in England and Wales in 2002/03.

as to its interpretation of NGET's reserve obligations and concerns over security of supply for that winter.

2.30. On both occasions, and after consultation with the relevant parties, we determined that the events or circumstances constituted IAEs, as in each case we considered that the events or circumstances were unforeseen at the time the SO incentive scheme was agreed, and no allowance had been made within the IBC target. The full amount of the proposed income adjustment was allowed in each case.

Proposed IAEs

2.31. On 30 June 2006, NGET submitted notices to us of proposed IAEs in respect of:

- management of within Scotland and Cheviot constraints (£18.54 million and £11.63 million respectively for a total of £30.18 million), and
- procurement of frequency response following the implementation of CUSC Amendment Proposal 047 (£5.59 million).

2.32. If the proposed income adjustment for each IAE were approved, NGET's IBC would fall to £391.5 million, which is still some £14 million higher than the target IBC in that year of £377.5 million

Role of the Authority

2.33. As set out in Chapter 1, and outlined in more detail in Appendix 3, following receipt of a proposed IAE, and after consultation with NGET, BSC and CUSC parties, we must determine:

- whether any or all of the costs detailed in the notice were the result of an IAE,
- whether the value of IBC changed by more than the threshold amount of £2 million, and
- if so, whether the amount of the proposed income adjustment ensures that the financial position and performance of NGET are, insofar as is reasonably practicable, the same as if that IAE had not taken place, and if not, what allowed income adjustment would secure that effect.

Summary

2.34. This chapter has looked at the general nature of SO incentive schemes that have applied to NGET in its role in operating the GB transmission system, and specifically that which applied in 2005/06. It also provides background to IAEs, including the relevant licence provisions, and previous IAEs that were approved by the Authority.

2.35. In the next chapter, we consider NGET's first notice, which relates to its proposed income adjustment in connection with internal to Scotland transmission system constraints and the Cheviot constraint.

3. Proposed IAE in respect of transmission system constraints

Chapter summary

This chapter sets out issues related to the management by NGET of internal to Scotland and Cheviot constraints that we consider are relevant in determining whether NGET has acted economically and efficiently in minimising constraint costs following the start of BETTA, and in determining whether any or all of its proposed income adjustment should be allowed. We set out our initial views and pose a series of questions on which we are particularly interested in gaining the views of interested parties.

Question box

Question 1: Do you consider that, prior to the start of the 2005/06 SO incentive period and based on available information at the time, NGET acted economically and efficiently in deciding to manage internal to Scotland and Cheviot constraints in the BM?

Question 2: Do you have any comments on whether the analysis we present in relation to forecasting the level of self-despatch of generation is appropriate in addressing this issue?

Question 3: Do you consider that, in November 2005, NGET acted economically and efficiently in managing internal to Scotland constraints through a commercial contract?

Question 4: Do you consider that NGET acted economically and efficiently in negotiating this contract?

Question 5: Do you have any comments on the methodology used by NGET in estimating the total cost of managing internal to Scotland and Cheviot constraints following the start of BETTA, and the amount of the proposed income adjustment?

Question 6: Do you have a view on the appropriateness of having separate cost allowances within the overall SO incentive scheme cost target?

System constraints

3.1. As discussed in Chapter 2, the role of the SO includes responsibility for:

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

3.2. A transmission related constraint arises where the system is unable to transmit the power supplied to the location of demand due to congestion at one or more parts of the transmission network. In the event that the system is unable to flow electricity in the way required, the SO will take actions in the market to increase and decrease the amount of electricity at different locations on the network. The exact way in which a constraint is managed depends on a number of factors including the nature of the flows on the transmission system, the local level of generation output, and the local level of system demand.

3.3. Managing a constraint often requires a reduction in the output from generation plants that had intended to self-despatch, and a compensating increase in generation output in another part of the system to maintain the overall system demand-supply balance.¹⁵ As a result, managing constraints usually results in costs being incurred by the SO. This is because the price that the SO must pay to a generating unit to increase its output tends to be higher than the price it receives from the generating unit that is required to reduce its output.

System operation under BETTA

3.4. As discussed in Chapter 2, prior to the introduction of BETTA, the SO role for the Scottish transmission network was undertaken by two integrated Scottish electricity utilities, Scottish Power (SP) and Scottish and Southern Energy (SSE). However, on 1 April 2005, the wholesale market arrangements that had been introduced for England and Wales in April 2001 were extended to cover Scotland as well, creating a single GB wholesale electricity market for the first time.¹⁶

3.5. These arrangements established a common set of trading rules allowing electricity to be traded freely across GB, as well as common rules for access to, and charging for, the GB transmission network. Importantly, BETTA also created a single GB-wide SO role, which saw responsibility for the SO role for the Scottish transmission system transferred to NGET. This also meant that management of constraints within Scotland, and their associated cost, became the responsibility of NGET.

¹⁵ This example relates to an export constraint. Import constraints can require units to be put on in the constraint area and units to be taken off elsewhere.

¹⁶ The GB wholesale market is based on bilateral trading between generators, suppliers, traders and customers across a series of markets. Consequently, generators are required to self-despatch their plants rather than have them centrally despatched by the SO.

Internal Scotland constraints

3.6. While there are a number of transmission system constraints within Scotland, the most significant in terms of NGET's proposed IAE exists in the North of Longannet to Scottish Hydro-Electric Transmission Limited network area, which NGET refers to as the NLOANSSE constraint.¹⁷ The only way that the SO is able to relieve this constraint is by requiring local generating units to despatch power (in other words, this constraint only arises when local generation chooses not to self despatch). Engineering studies undertaken by NGET established that an amount of local generation would be needed to alleviate this constraint even under normal 'intact' conditions during winter.¹⁸

3.7. We understand that prior to BETTA, this constraint was managed through an internal agreement between SP and SSE, under which local generation around the NLOANSSE constraint was despatched specifically to mitigate the constraint. Given that such an agreement for the management of this constraint was internal between SP and SSE, the cost of managing this constraint would have been borne by these two companies (and ultimately, their customers).¹⁹ It would appear that the costs of managing this constraint were not transparent.

Cheviot constraint

3.8. A further constraint, known as the Cheviot constraint, exists on the England-Scotland border, and is caused by a combination of excess generation output in Scotland over Scottish demand, and a relative shortage of transmission capacity across the border to England. The extent of this constraint in 2005/06 is illustrated in Table 3.1 below.

3.9. This table shows that under peak conditions in 2005/06, the size of the Cheviot constraint would be around 161MW. However, the actual size of the constraint on a daily basis depends on a number of factors including the actual level of transmission capacity available, and actual levels of generation output and electricity demand in Scotland. As a consequence, on certain days (for example when demand in Scotland was at average levels and generation was at peak levels), the extent of this constraint could be up to 2,424 MW.²⁰

¹⁷ Technically, this is termed a "voltage constraint", which requires reactive power provision from local generation and/or a minimum level of local generation output to ensure that voltage levels are maintained within GBSQSS limits. This constraint accounted for almost 90 percent of internal Scotland constraints costs in 2005/06.

¹⁸ 'Intact' conditions refers to the normal operation of that part of the transmission system, and means that the capacity of the system was not reduced due to 'planned' outages or 'fault' outages.

¹⁹ NGET has indicated that it was not party to the arrangements to manage constraints within Scotland and therefore does not know definitively how these internal constraints were managed pre-BETTA.

²⁰ NGET has advised that the scenarios in the table are essentially artificial as the circumstances did not necessarily exist.

Table 3.1: The Cheviot constraint, 2005/06²¹

	Peak generation Seen & Peak demand Seen	Peak generation seen & average demand seen	Average generation seen & average demand seen
Scotland generation capacity	8,563 MW	8,563 MW	4,890 MW
Demand in Scotland	6,202 MW	3,939 MW	3,939 MW
Surplus capacity	2,361 MW	4,624 MW	951 MW
Cheviot capacity	2,200 MW	2,200 MW	2,200 MW
Size of Cheviot constraint	161 MW	2,424 MW	0 MW

3.10. Prior to the commencement of BETTA, the Cheviot constraint was managed through interconnector agreements between NGET (as the SO of the England and Wales transmission system), and SP and SSE, who operated the Scottish transmission network. These agreements effectively restricted access to the England and Wales market for the Scottish generators, consistent with the level of transmission capacity available on the Cheviot interconnector.

3.11. As part of these agreements, transmission system to generation intertripping schemes were also installed, which allowed increased pre-fault levels of electricity exports across the Cheviot interconnector from Scotland by providing for automatic reduction in generation in Scotland in the event of critical transmission system faults on the Cheviot circuits.

3.12. With the start of BETTA, these agreements ended, effectively allowing all Scottish generation full unconstrained market access to England and Wales. As a consequence, NGET became responsible for managing this constraint (and the associated costs) through standard constraint management actions.

3.13. The terms on which the intertripping schemes that had previously been installed would be available to NGET following the commencement of BETTA formed part of the negotiation of Bilateral Connection Agreements (BCAs) in January and February 2005. NGET sought to continue to treat the schemes as operational intertrips, while the Scottish generation companies argued that they should be considered as commercial intertrip schemes. The matter was referred by the companies to us for determination, and in August 2005 we concluded that each of the intertrip schemes should be deemed to be commercial schemes.

²¹ Data source: estimates provided by NGET 2 August 2006. Scottish demand includes exports to Ireland via the Moyles interconnector.

3.14. NGET has indicated that following the determination of the nature of the intertrip schemes, it commenced negotiations with the Scottish generation companies to put in place a commercial agreement regarding the use of the intertrip, which was signed on 6 June 2006.

Proposed IAE

3.15. In this section, we outline details of NGET's claim, and provide an overview of the methodology used by NGET in calculating the cost of managing internal to Scotland constraints and the Cheviot constraint following the start of BETTA.

Proposed income adjustment

3.16. As outlined in Chapter 2, an additional £30 million was included in NGET's SO incentive target in 2005/06 to reflect additional system operation costs following the commencement of BETTA. This figure was made up of £10 million in respect of the internal Scotland constraints and a further £20 million for the management of the Cheviot constraint.

3.17. However, NGET has estimated that the actual cost of managing these constraints was £60.18 million, which represents an increase of £30.18 million over the allowance included in the 2005/06 scheme, the amount of NGET's proposed income adjustment. The cost NGET says it incurred in relation to each constraint is as follows:

- £28.54 million for internal to Scotland constraints, giving rise to a proposed income adjustment of £18.54 million, and
- £31.63 million for the Cheviot constraint, leading to a proposed income adjustment of £11.63 million.

NGET's costing methodology

3.18. NGET's estimate of the total cost of managing both the internal Scotland and Cheviot constraints reflects the net cost of market actions it states were required to manage these constraints (and which it would not otherwise have taken), plus the cost of commercial contracts it entered into to manage constraints within Scotland.

3.19. In identifying these costs, NGET has stated it:

- identified all of the actions it took to manage Scottish constraints, and whether these were 'energy' or 'system' actions, and whether the action created 'margin'²²,
- identified the volumes associated with each constraint action,
- identified the prices associated with each constraint action, including where appropriate, the price of actions taken to re-balance the system²³, and
- determined the net cost of managing each constraint.

3.20. NGET estimated the total net cost of the market actions required to manage the Scottish constraints by summing the net cost of each individual constraint action taken.

Ofgem views

3.21. Following submission of NGET's notice of the proposed IAE, we formally requested, and were provided with, a range of additional information to help us further analyse its submission. A copy of our letter to NGET is included in Appendix 4.

3.22. In assessing NGET's proposed IAE, we analysed whether:

- an increase in constraint management costs following the commencement of BETTA was foreseeable,
- NGET acted economically and efficiently in minimising constraint management costs following the commencement of BETTA, and
- the methodology it used to calculate the amount of its proposed income adjustment was appropriate.

3.23. Each of these issues is addressed below in turn for internal to Scotland constraints and the Cheviot constraint.

Was an increase in constraint costs foreseeable?

3.24. As noted in Chapter 2, in setting the target for NGET's SO costs in the 2005/06 incentive scheme, we recognised that NGET's costs would increase following the commencement of BETTA as it would become responsible for energy and system balancing for the whole GB transmission system, including Scotland. It was also

²² NGET identified Scottish constraint action through a post-event monitoring and review process, which was independently audited by PricewaterhouseCoopers (PwC). PwC concluded NGET's process operated effectively in this regard. Appendix 5 provides a more detailed overview of the categorisation of constraint actions by NGET, and the impact on the costing process.

²³ Ibid.

recognised that NGET would incur further costs in managing the Cheviot constraint through standard market actions, as the capacity agreements that restricted access to the England and Wales market for the Scottish generators ended with the start of BETTA.

3.25. NGET originally estimated that its costs would rise by £54 million as a result, with the management of internal to Scotland transmission constraints costing £17 million, and the Cheviot constraint a further £36.9 million.

3.26. However, significant uncertainties existed regarding the level of these costs as the cost of both constraints had been internalised by the Scottish companies, and limited information was available on the economic and efficient cost of managing these constraints. As a result, an additional £30 million was included in NGET's SO incentive target in 2005/06, reflecting £10 million for internal Scotland constraints and a further £20 million for the Cheviot constraint.

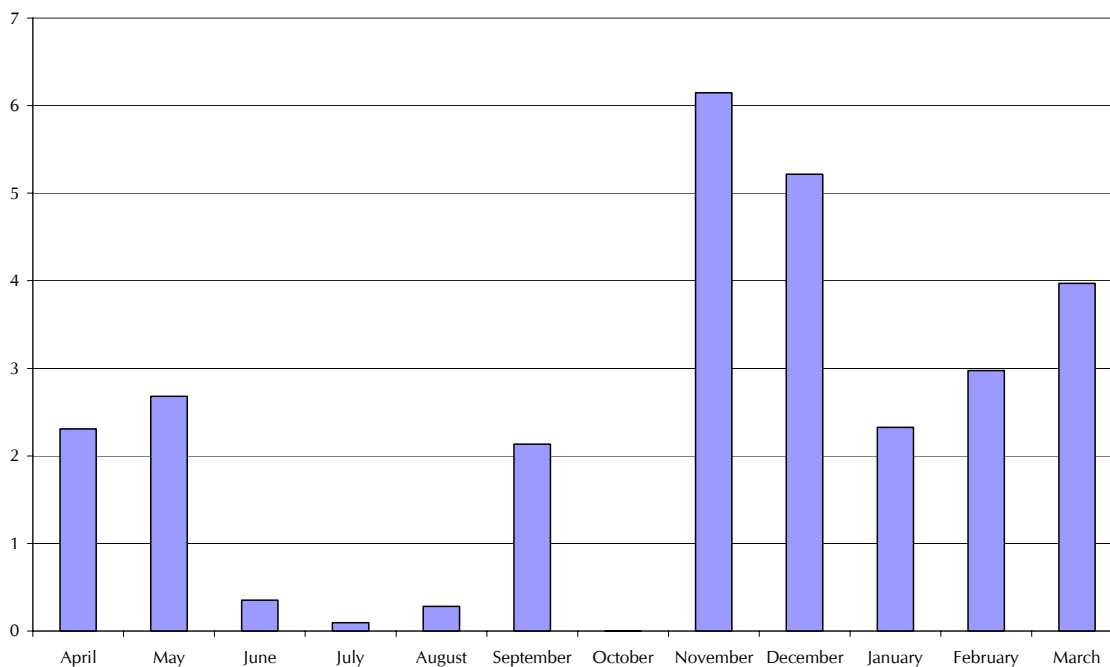
3.27. As noted earlier, we did request that market participants be kept informed of the costs that were being incurred by NGET in managing internal to Scotland transmission constraints and the Cheviot constraint, and we note that NGET provided updates on these costs to industry participants through the Operational Forum in February 2006 and June 2006.

NGET's approach to managing constraint costs

3.28. Having seen that an increase in NGET's SO costs was expected following the commencement of BETTA, the following section considers whether NGET acted economically and efficiently in minimising the additional costs incurred in managing internal to Scotland transmission constraints and the Cheviot constraint.

Internal to Scotland constraints

3.29. As illustrated in Figure 3.1, in the seven months from April to October 2005, NGET incurred costs of around £7.9 million, almost 80 percent of the allowance in the 2005/06 SO incentive scheme, in managing internal to Scotland constraints. In the following month alone, further costs of over £6 million were incurred by NGET for the NLOANSSE constraint, and total internal to Scotland constraint management costs for the year eventually exceeded £28 million.

Figure 3.1: Internal to Scotland Constraint costs - 2005/06 (£M)

3.30. Consequently, we separately analysed whether NGET acted economically and efficiently in minimising constraint costs within Scotland:

- by electing, prior to the commencement of BETTA, to despatch additional generation in the BM if constraints became active, particularly in connection with the NLOANSSE constraint, and
- by commencing negotiation of a Winter Security Service commercial agreement ('the WSS agreement') with SSE in November 2005.

NGET's Pre-BETTA strategy

3.31. NGET has stated that prior to April 2005, it had concluded that the despatch of generation local to the NLOANSSE constraint would be necessary for constraint management purposes. It indicated that although it had investigated a range of options to manage the NLOANSSE constraint prior to the commencement of BETTA, it determined that the most economic and efficient management of the constraint in the short term was to rely on local generation.²⁴

²⁴ In particular, the other options investigated by NGET included applying for a derogation from relevant safety standards and investment in new equipment

3.32. NGET also concluded that there was no need to contract for the despatch of this generation in advance. In part, it based this decision on:

- the fact that only a relatively small volume of the generation capacity within the NLOANSSE constraint area was required to alleviate the constraint²⁵, and
- historical analysis of the despatch patterns of relevant generators suggested there was likely to be a sufficient level of self-despatch by generators.

3.33. NGET also stated that it further analysed the operation of two large Balancing Mechanism Units (BMUs) at Peterhead Power Station (Peterhead) owned by SSE, as the despatch of either of these units would be sufficient to manage the constraint. It concluded there was a high likelihood of sufficient generation from these Peterhead BMUs given their:

- multi-fuel capabilities - these BMUs were known to be able to operate on National Transmission System gas, Miller gas and oil,
- generation efficiency relative to other units in the GB fleet, and
- advised availability.²⁶

3.34. Based on this analysis, NGET concluded that there were likely to be only a limited number of occasions on which sufficient generation would not be self-despatched from Peterhead. As a result, it determined that the most efficient and effective manner to manage the NLOANSSE constraint, when it became active, would be to despatch additional generation in the BM.

3.35. We consider that a fundamental issue to analyse is whether, at the time NGET was determining the most appropriate way of managing internal to Scotland constraints, it was reasonable to assume that sufficient generation local to the NLOANSSE constraint would choose to self-despatch.

3.36. In addressing this question, we:

- created a stack of generation types, ranked in order of marginal cost of production, to show which types of generation could be expected to self-despatch at different wholesale electricity prices,
- used winter 2005/06 forward prices for coal, oil and gas that NGET would have observed in April 2005 in developing this ranking,
- estimated where generation local to the NLOANSSE constraint sat in this merit order after accounting for differences in transmission charges, and

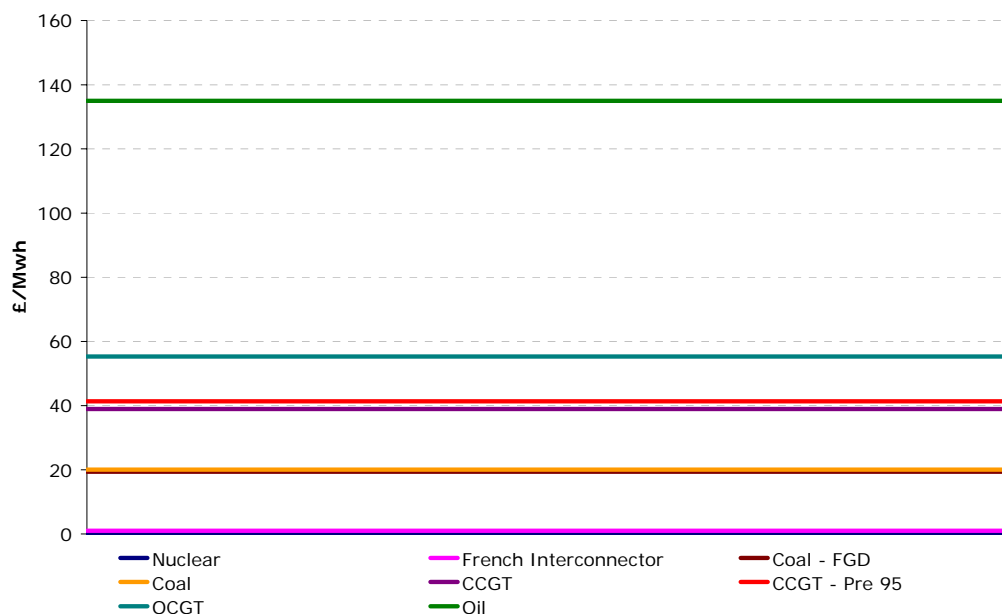
²⁵ NGET estimated that around 200MW of output from 2,000MW of capacity from a combination of Peterhead, Foyers and Fife power stations would be required during winter daytime to secure the transmission system.

²⁶ NGET also considered that the fact that the unit had just come back from outage/maintenance was also a factor in determining that it was likely to run.

- assessed whether it was reasonable for NGET to assume that generation local to the NLOANSSE constraint would self-despatch in sufficient volumes to alleviate the constraint on the basis of April 2005 forecasts of winter 2005/06 electricity demand.

3.37. Our initial step was therefore to develop the ranking of generation types based on forecasts of marginal costs of generation for winter 2005/06 (observed in April 2005). This ranking is illustrated in Figure 3.2 below.

Figure 3.2: Estimated ranking of generation by marginal cost of despatch for winter 2005/06



3.38. As noted above, this ranking of generation (in order of relative marginal costs of production) was derived using winter 2005/06 forward prices for fuel as seen in April 2005 and incorporates average transmission charge data. This data is presented in Appendix 5.²⁷

3.39. The majority of generation local to the NLOANSSE constraint is of the category 'pre-1995 CCGT' plant. Figure 3.2 therefore shows that this plant would choose to self-despatch before oil-fired plant, but only after more efficient forms of CCGT plant, coal plant and nuclear.

²⁷ Note that actual fuel costs over winter 2005/06 were far higher than forward prices in April 2005 suggested. However it is the expectation of fuel prices for winter 2005/06 in April 2005 that is of relevance to our analysis (i.e. the time at which NGET was determining the most appropriate way of managing transmission system constraints for the coming winter).

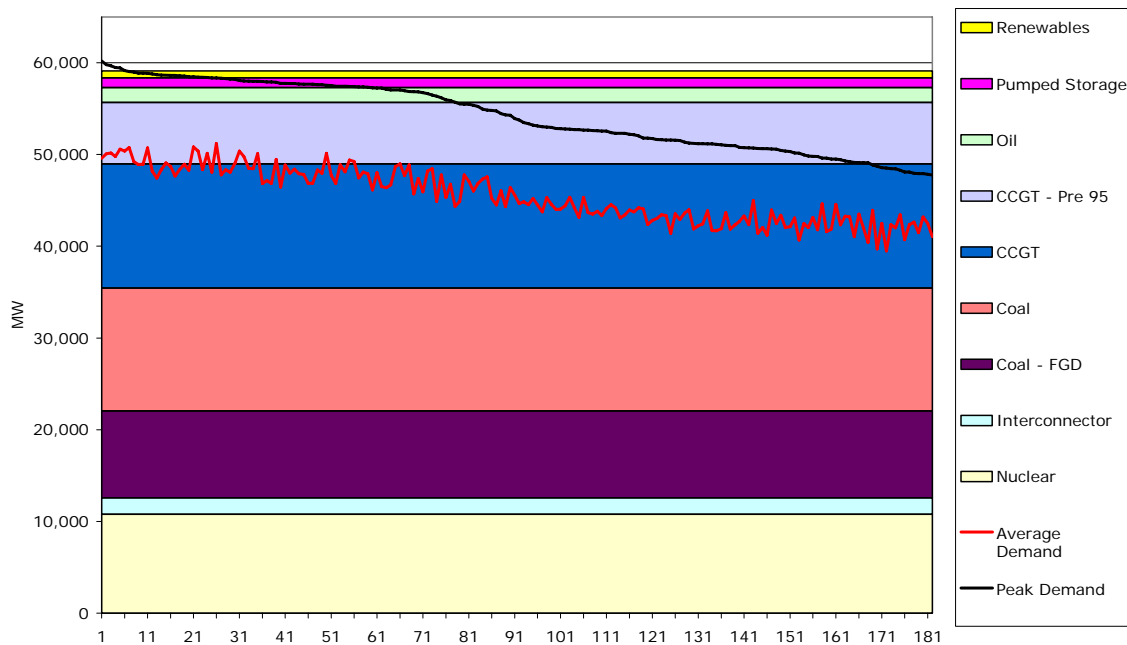
3.40. In April 2005 when NGET was estimating whether generation local to the NLOANSSE constraint would self despatch in winter 2005/06, data on bookings of Transmission Entry Capacity (TEC) rights for each generating site in GB, and peak and average forecast levels of GB system demand for winter 2005/06 would also have been available to it. By combining these data, it is possible to assess the number of days for which different generation types may be likely to choose to self despatch over winter 2005/06. This is illustrated in Figure 3.3.

3.41. Figure 3.3 shows that, on the basis of winter 2005/06 forward prices for fuel, forecast levels of system demand and bookings of TEC, 'pre-1995 CCGT' plant may only have been expected to run for around 23 days over winter 2005/06 under average demand conditions. This increases to around 90 days under peak demand conditions.

3.42. If the assumption is made that generation local to the NLOANSSE constraint represent the most costly forms of pre 1995 CCGT plant, then under average demand conditions, this form of plant may not be expected to run at all. This analysis would suggest that even under peak demand conditions, expensive pre-1995 CCGT would only run for 78 days of the winter period.

3.43. Although the actual availability of forms of generation that are less costly than pre-95 CCGTs may be below their bookings of TEC, this analysis suggests that sufficient evidence existed in April 2005 to indicate there was a significant risk that relatively costly forms of pre-1995 CCGT plant would choose not to self-despatch over winter 2005/06.

Figure 3.3: Forecast generation despatch in response to peak and average levels of demand in winter 2005/06



3.44. This analysis suggests that NGET could have foreseen in April 2005 the extent of internal to Scotland transmission constraints in winter 2005/06.

3.45. While NGET has advised us that it concluded sufficient generation from the two large Peterhead BMUs was highly likely given advised plant availability, multi-fuel capability and relative efficiency, it is unclear whether these assumptions were tested with SSE. In particular, the assumption that Peterhead could be expected to generate using Miller gas or oil if high gas prices were to eventuate.

3.46. In this context, we have previously been advised by SSE that Peterhead Module 1 has an efficiency rating of around 50 percent if operating in CCGT mode but the timescales involved in shifting, limits the unit's flexibility for economic purposes. While Unit 2 is flexible, it has economics more akin to an oil unit. SSE have also advised that it would normally take Peterhead offline first of all of its gas stations. We also understand that supply of gas from the Miller reserve, which is in decline, is not able to be scheduled by SSE as its flow is dependent on the build-up of sufficient pressure, and when available is provided on a must take basis.

3.47. We believe this information would have been known to NGET, and should have increased uncertainty prior to 2005/06 surrounding the level of self-despatch of generation that could be expected within the NLOANSSE constraint area.

3.48. In combination with the analysis presented above, our initial view is that sufficient evidence exists to suggest that NGET should have been able to foresee the extent of constraint management necessary in 2005/06 to relieve internal to Scotland constraints. This raises the issue of whether it would have been more economic and efficient to have contracted ahead to manage this constraint.

NGET's November 2005 strategy

3.49. In November 2005, NGET identified that system demand within the NLOANSSE constraint area was such that there was likely to be a recurring need for Peterhead to despatch power on a daily basis through winter 2005/06. Initially, NGET chose to meet this requirement through the BM. The BM actions taken by NGET to manage the NLOANSSE constraint in November 2005 were:

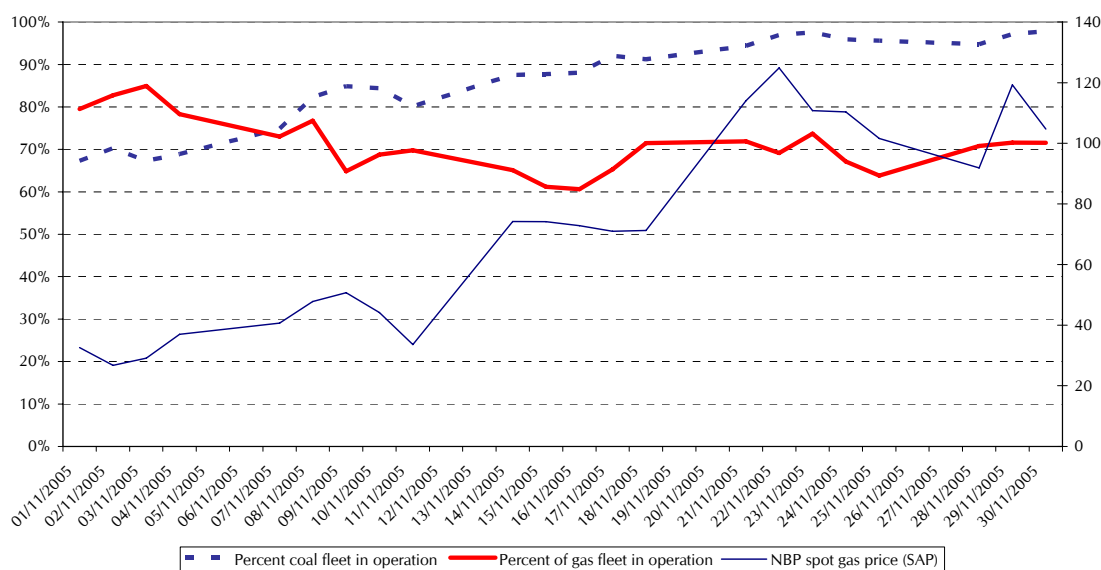
- pre-gate closure balancing trades (PGBTs) with Peterhead Units 1 and 2 between 9 and 17 November and 24 and 25 November, at prices ranging from £200MWh to £440MWh,
- BM offers with Peterhead Units 3 and 4 on 26 and 27 November priced at £595MWh and £750MWh, and
- from 28 to 30 November, NGET entered into Schedule 7a commercial arrangements.

3.50. NGET advised that up until 24 November 2005, it still considered it possible that sufficient generation would be self-despatched within the NLOANSSE constraint area, avoiding the need for it to take action in the market. However, NGET indicated that, with continued rises in spot and forward gas prices for the remainder of winter,

at that point it decided to pursue longer term contracts and trades as a more economic alternative to procurement through the BM.

3.51. The impact of rising gas prices on despatch profiles in November 2005 is illustrated in Figure 3.4, and shows that as the gas price increased as much as four-fold during the month, the percentage of output from the GB gas generation fleet fell from 80 percent to a low of around 60 percent before rising back to just over 70 percent. The figure also illustrates that coal generators replaced much of the loss in gas generated output, with close to 100 percent of coal fleet capacity generating by the end of the month.

Figure 3.4: Gas and coal generation output versus gas price - November 2005



3.52. NGET commenced discussions with SSE to secure Peterhead generation output through a longer term contract in order to manage the NLOANSSE constraint in late November, and while this contract, the WSS agreement, was being negotiated, NGET agreed BMU specific trades with SSE on a week by week basis over the period from 28 November to 22 December 2005.

3.53. NGET has advised that the WSS agreement was agreed in principle on 22 December 2005, and commenced operationally on that day, despite not being formally signed until 10 March 2006. NGET has stated that the agreement is constructed to ensure that payments, which resulted in a significant cost saving to NGET relative to PGBT and commercial prices paid, reflected NGET's minimum requirement for generation.

3.54. The information provided by NGET in its notices indicates it did take actions to minimise the impact of increased in BM prices on the management of the NLOANSSE constraint. However, as the price and terms of the final agreement was determined through bilateral negotiation between SSE and NGET, it is difficult to determine

whether the agreement reflects the most economic and efficient outcome that could have been achieved by NGET in minimising the cost of the NLOANSSE constraint.

3.55. Therefore, we would welcome views on this from interested parties including on whether NGET's actions in managing the NLOANSSE constraint during November and December leading up to the WSS agreement were economic and efficient. We would particularly invite parties to provide copies of any relevant correspondence or details of any discussions that the parties may have had with NGET, if necessary on a confidential basis.

Cheviot constraint

3.56. NGET has advised that the terms under which a transmission system to generation intertripping scheme, discussed previously, would be available to NGET were not finalised during 2005/06. However, NGET has indicated that it believes that at prices indicated to it, constraint management costs through the intertrip would have been comparable to the cost of alternative actions.

3.57. While almost half of Cheviot constraint costs were incurred under planned outage conditions, NGET has also advised that as the constraint is driven by the combined actions of Scottish generators, it would be complex and, in its opinion, uneconomic, to attempt to contract to manage aggregate Scottish generation output to manage this constraint.

3.58. We note that while there is a relatively large number of generation plant in Scotland, ownership of generation output capacity is relatively concentrated with British Energy holding around 45 percent, SSE around 34 percent and SP almost 20 percent. We would welcome views on whether respondents agree with NGET's assessment that the most economic and efficient manner in to manage the Cheviot constraint was through the BM.

Costing methodology

3.59. Finally, we reviewed the methodology NGET used to calculate the amount of its proposed income adjustment. Our initial view is that NGET's methodology may overstate the level of costs that can be attributed to managing the internal to Scotland and Cheviot constraints.

3.60. We note that the energy reference price is calculated as a half hourly varying value based on submitted prices at gate closure in England and Wales.²⁸ While this appears appropriate in calculating Cheviot constraint costs, it is unclear why prices

²⁸ NGET's equation 1 in Appendix 1, p.32.

for feasible Scottish plant should not be included in determining the reference price for managing constraints within Scotland.²⁹

Summary of Ofgem's views

3.61. Based on our analysis of information that would have been available to NGET prior to the start of the 2005/06 incentive period, our initial view is that sufficient evidence existed to suggest that NGET should have been able to foresee the extent of constraint management necessary in 2005/06 to relieve internal to Scotland constraints. Negotiation ahead of November could have significantly reduced NGET's costs.

3.62. Without further information, we are unable to conclude whether the agreement negotiated by NGET in November 2005 to manage the NLOANSSE constraint reflects the most economic and efficient outcome that could have been achieved by it in minimising the cost of the NLOANSSE constraint.

3.63. Therefore, we would welcome views on this from interested parties, and in particular SSE, including on whether NGET's actions in managing the NLOANSSE constraint during November and December leading up to the WSS agreement were economic and efficient. We would particularly invite parties to provide copies of any relevant correspondence or details of any discussions that the parties may have had with NGET, if necessary on a confidential basis.

3.64. Given the concentration of market participants in Scotland, we would also invite views on NGET's assessment that the Cheviot constraint could be most economically and efficiently managed through the BM.

3.65. Finally, our initial view is that NGET's costing methodology may in a number of instances not identify the actual cost of managing internal to Scotland and Cheviot constraints as costs reflect in a number of instances, the reference prices that are utilised may be calculated excluding 'feasible' volumes and prices.

Summary

3.66. This chapter has looked at issues related to the management of internal to Scotland and Cheviot constraints by NGET that we consider are relevant in determining whether NGET has acted economically and efficiently in minimising constraint costs following the start of BETTA, and in determining whether any or all of its proposed income adjustment should be allowed. We have set out our initial views and posed a series of questions on which we are particularly interested in gaining the views of interested parties.

²⁹ 'Feasible' in this context refers to generation capacity that is not subject to the constraint.

3.67. In the next chapter, we consider NGET's second notice, which relates to its proposed income adjustment in connection with the increase in frequency response costs following the implementation of CAP047.

4. Proposed IAE in respect of frequency response

Chapter summary

This chapter sets out issues related to the procurement of frequency response by NGET that we consider are relevant in determining whether NGET has acted economically and efficiently in minimising frequency response costs following the implementation of CAP047, and in determining whether any or all of its proposed income adjustment should be allowed. We set out our initial views and pose a series of questions on which we are particularly interested in gaining the views of interested parties.

Question box

Question 1: Do you consider that NGET has acted economically and efficiently in procuring frequency response to minimise costs?

Question 2: Do you have any comments on the methodology used by NGET in estimating the total cost of procuring frequency response following the implementation of CAP047, and the amount of the proposed income adjustment?

Question 3: Do you have any comments on our proposed alternative methodology, and the amount of the income adjustment that may result should we determine that the events or circumstances surrounding the increase in frequency response costs incurred by NGET is an IAE?

Question 4: Do you have a view on the appropriateness of having separate cost allowances within the overall SO incentive scheme cost target?

Frequency response

4.1. As discussed in Chapter 2, one of the roles of the SO is to ensure that the transmission system remains within safe operating limits, including managing the frequency of the system, a continuously changing variable that is determined and controlled by the balance between system demand and total generation.³⁰ If demand is greater than generation output, the frequency falls while if generation is greater than demand, the frequency rises. NGET has a licence obligation to maintain frequency within $\pm 1\%$ of the nominal system frequency of 50Hz save in abnormal or exceptional circumstances. NGET must therefore ensure that sufficient generation and / or demand is held in automatic readiness to manage all credible frequency change contingencies, that is to provide 'frequency response' if required by NGET.

³⁰ For a more detailed discussion on frequency response, see <http://www.nationalgrid.com/NR/rdonlyres/2106CEB2-E2C0-4AC9-A8FE-940DEFCCCEB/3273/frequency.pdf>

4.2. All licensed generators are obliged under the Grid Code to provide mandatory frequency response, which relates to a specific form of frequency response termed 'dynamic' frequency response.³¹³² Prior to 1 November 2005, NGET procured mandatory frequency response via non-tendered bilateral contracts, with payments made under the CUSC being calculated in accordance with 'cost reflective' charging principles and consisting of a Holding Payment and a Response Energy Payment. The Holding Payment is paid for each minute during the period that the generator is held on standby, whilst the Response Energy Payment is paid for the expected volume of frequency response delivered.

4.3. Dynamic and non-dynamic frequency response may also be procured by NGET through the commercial services route. Commercial services are freely negotiated between NGET and the service providers both in terms of contract form and price.

Changes to mandatory frequency response arising from CAP047

4.4. The introduction of an amendment to the CUSC, CAP047, on 1 October 2005 removed the administered 'cost-reflective' basis for setting Holding Payment prices. Following this change, generators were able to price freely this aspect of their mandatory frequency response service.³³

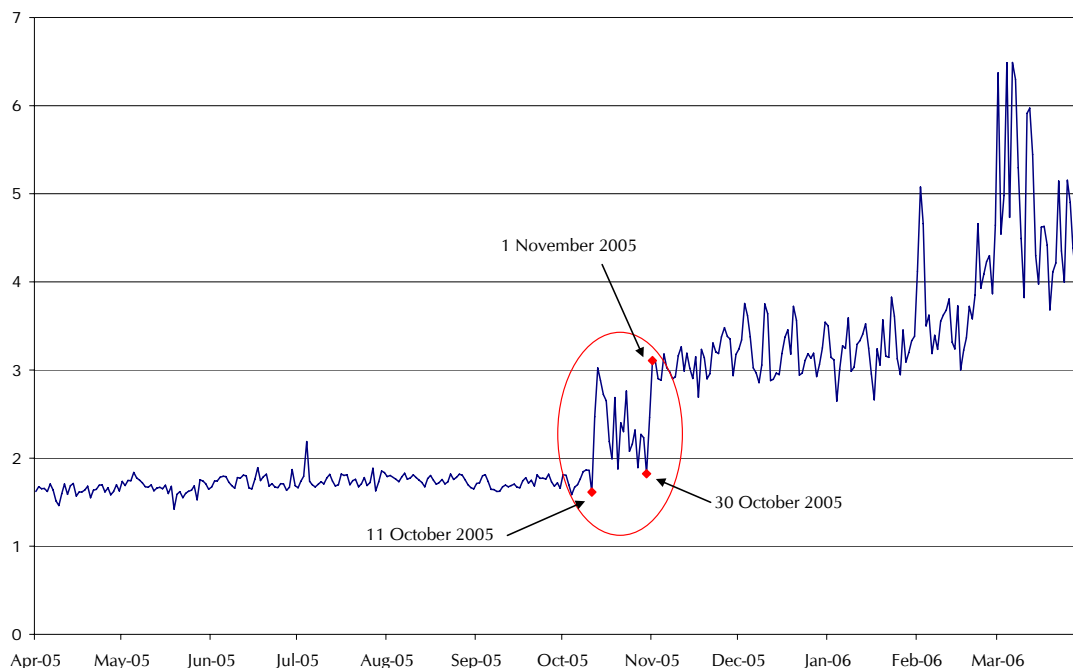
4.5. Figure 4.1 shows that before the implementation of CAP047 pricing on 1 November 2005, prices generally moved in a relatively small band throughout 2005/06, although there was unexpectedly high volatility in prices between 11 and 30 October 2005. NGET stated this volatility was due to a despatch error resulting from a new frequency response provider being despatched on indicative contract prices, but settled at higher final contract prices, which had not been updated in NGET's despatch file.³⁴

³¹ Some generators hold derogations that relieve them of this obligation.

³² Frequency response is divided into either dynamic or non-dynamic (or static), where dynamic frequency response relates to the continual regulation of load in response to changes in system frequency, while non-dynamic frequency response may be automatically triggered by a relay.

³³ For further information on CAP047 see Ofgem's Connection and Use of System Code Proposed Amendment CAP047: "Introduction of a competitive process for the provision of mandatory frequency response" Impact Assessment, August 2004, (reference 210/04), available at http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/8441_cap047ia_final.pdf?wtfrom=/ofgem/whats-new/archive.jsp

³⁴ Adjusting for this event, NGET advised that the average Holding Payment price in October 2005 would have been £1.75MWh, which is broadly consistent with the level in the previous four months.

Figure 4.1: Average daily Holding Payment prices - 2005/06 (£/MW/h)

4.6. Available data demonstrates that there was a marked and observable step change in average daily Holding Payment prices following the implementation of CAP047.

Proposed IAE

4.7. In this section, we outline details of NGET's claim, and provide an overview of the methodology used by NGET in calculating the increase in its costs of procuring frequency response as a result of the introduction of CAP047.

Proposed income adjustment

4.8. As outlined in Chapter 2, an allowance of £7.35 million was included in NGET's 2005/06 incentive scheme to take account of the potential increase in the cost of procuring frequency response following the implementation of CAP047.

4.9. However, NGET has estimated that the cost of procuring frequency response actually increased by £12.94 million as a result of the introduction of CAP047. This represents an increase over the allowance included in its incentive scheme of £5.59 million, for which NGET is claiming an IAE and an equal cost reduction to its actual IBC. The following section outlines how NGET has calculated this cost estimate.

Costing methodology

4.10. NGET's overall estimated increase of £12.94 million in the cost of procuring frequency response following the implementation of CAP047 comprises:

- an increase in its mandatory frequency response costs of £10.99 million, and
- an increase in the cost of procuring other alternative frequency response that NGET attributes to the implementation of CAP047 of £1.95 million.

Increase in mandatory frequency response costs post-CAP047

4.11. NGET estimated the increase in mandatory frequency response costs following the implementation of CAP047 by calculating the additional costs it had to pay over and above those it believes it would have paid had CAP047 not been introduced. In calculating this figure, NGET states it:

- identified the volume of mandatory response it procured each month in November 2005 (when CAP047 was implemented) to March 2006 (when the incentive scheme ended),
- identified the average monthly holding price it paid for this volume of response, and
- estimated the average monthly holding price it would have paid for this volume of response had CAP047 not been implemented.

4.12. NGET estimated that, had CAP047 not been implemented, average Holding Payment prices in November 2005 to March 2006 would have been 4.16 percent higher than in the corresponding period in 2004/05. This estimate was based on:

- increases in the retail price index, ranging between 2 and 3 percent per annum, which it averaged to 2.5 percent, and
- increases of around 5 percent for a third of generators each year as a result of a triennial review of mandatory frequency response prices³⁵ (i.e. increasing aggregate prices by an average of 1.66 percent per annum).

4.13. Therefore, the estimated cost of £10.99 million represents the volume of mandatory response multiplied by the difference between the actual post-CAP047 Holding Payment price and the actual average price paid in the corresponding month in 2004/05 indexed by 4.16 percent.³⁶

35 The triennial review was undertaken by NGET in accordance with the CUSC and allowed generators and NGET to suggest revisions to pricing level and price calculation methodology.

36 The monthly breakdown is shown in Figure 5 on page 13 of NGET's submission.

Impact on alternative frequency response costs post-CAP047

4.14. NGET claims that a portion of the increase in the cost of firm frequency response, an alternative source of frequency response, can be attributed to the implementation of CAP047. It calculated this amount by multiplying the volume of firm frequency response procured each month from November 2005 to March 2006 by the difference between the actual post-CAP047 Holding Payment price and the actual average price paid in the corresponding month in 2004/05 indexed by 4.16 percent (as detailed above).

4.15. NGET argues that it is appropriate to include this 'notional' attribution of the CAP047-effect on firm frequency response costs, as mandatory frequency response costs are used as the benchmark against which it makes an economic assessment of firm frequency response tenders. NGET considers that as the comparator benchmark (i.e. mandatory frequency response costs), increased due to CAP047, higher priced firm frequency response was despatched than would have been the case had CAP047 not been implemented.

Ofgem's views

4.16. Following submission of NGET's notice of the proposed IAE, we formally requested, and were provided with, a range of additional information to help us further analyse its submission. A copy of our letter to NGET is included in Appendix 4.

4.17. In assessing NGET's proposed IAE, we analysed:

- the potential factors influencing Holding Payment prices pre and post-CAP047;
- whether NGET acted economically and efficiently in minimising frequency response costs following the implementation of CAP047, and
- whether the methodology it used to calculate the amount of its proposed income adjustment is appropriate.

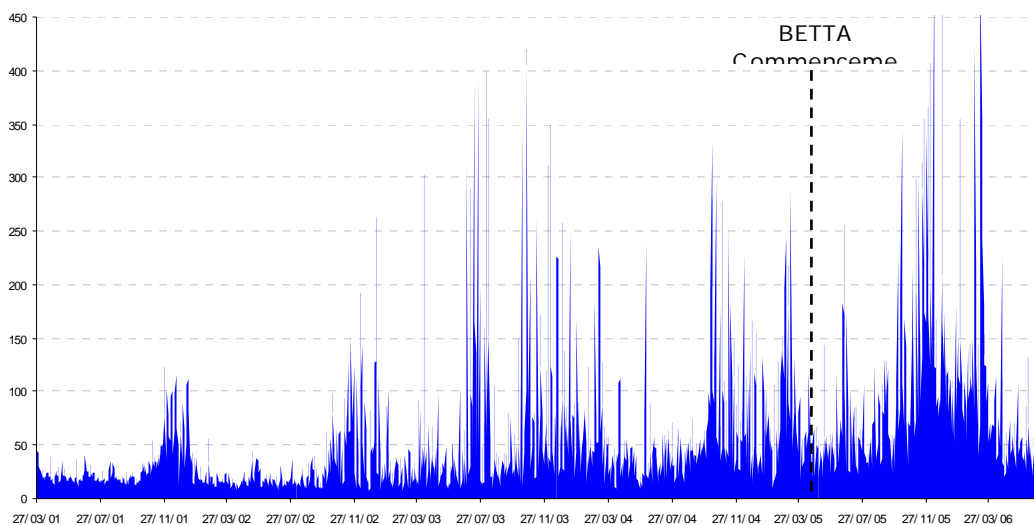
4.18. These are discussed in turn in the following sections.

Holding Payment prices

4.19. As noted previously, the commencement of CAP047 pricing on 1 November 2005 removed the administered 'cost-reflective' basis for setting Holding Payment prices. However, Response Energy Payment pricing continued to be administratively determined, based on retrospective market prices. Consequently, it is possible that additional costs, not previously recovered through either the Holding Payment or the Response Energy Payment, were being incorporated in Holding Payment pricing post-CAP047.

4.20. For example, uncertainty surrounding the level of usage of frequency response by NGET may mean that generators attach a risk premium to providing mandatory response, which was not a recognised as a 'cost' in setting the Holding Payment price before CAP047. As Holding Payment rates under CAP047 can only be changed once a month by generators for use in the successive calendar month, the increased spread between intra-day maximum and minimum prices (i.e. the level of energy price volatility) as shown in Figure 4.2 may lead to a further rise in the level of such a risk premium.

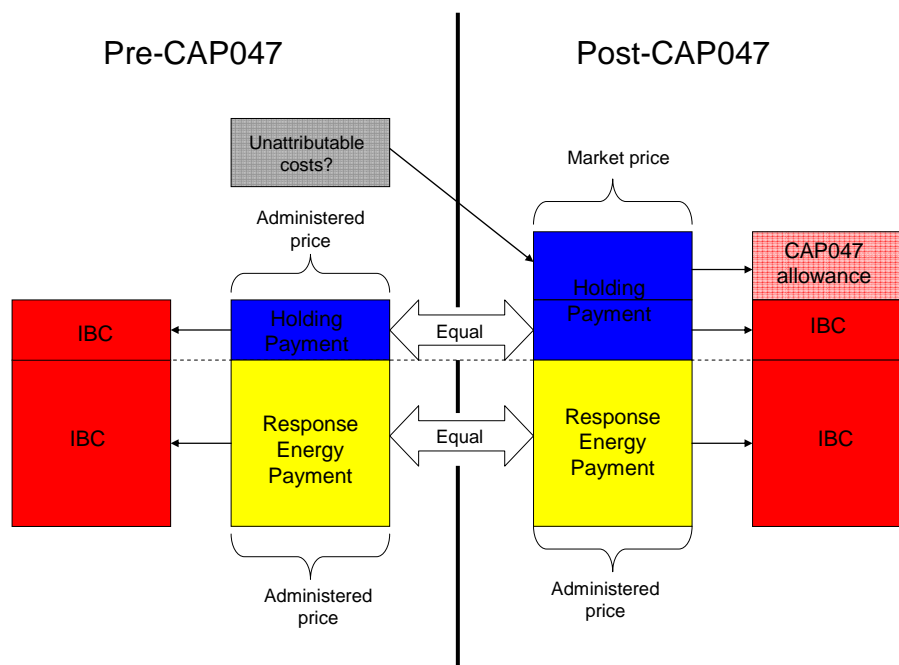
Figure 4.2: Energy price volatility - 2001/02 to 2005/06 (£/MW/h)



4.21. In addition, the average and retrospective nature of the calculation of the Response Energy Payment may not reflect actual costs incurred by different individual generators at the time each may be required to provide frequency response. An individual generator's costs, based on varying types of fuel and generation technologies, may differ from the Reference Price used to actually calculate the Response Energy Payment that is paid to, or by, it.

4.22. As illustrated by Figure 4.3, following the implementation of CAP047 pricing, it is possible that these costs (or perceived costs) incurred by generators, but which they were not able to recover under the old administered pricing arrangements, were now able to be wrapped into the Holding Payment. This is shown in Figure 4.3 by the increase in the blue Holding Payment box, which now incorporates the light grey box in the top left of the figure representing costs previously not recovered through frequency response payments.

Figure 4.3: Possible pre and post-CAP047 mandatory frequency response pricing



4.23. Figure 4.3 also demonstrates that while underlying frequency response costs may not have changed, the level of costs that are included within NGET's IBC could still have increased. We are concerned that including a separate allowance for CAP047 costs within NGET's 2005/06 IBC target may have removed the incentive for NGET to efficiently and economically manage mandatory frequency response costs following CAP047.

4.24. If NGET had specific concerns over this issue prior to 1 November 2005, we would have expected it to propose a rule change to mitigate this issue in advance. In this context, we note that in early December 2005 a third party raised CUSC amendment proposal (CAP107) in relation to the calculation of the Response Energy Payment component of mandatory frequency response, which it has been claimed may be contributing to the increase in Holding Payment prices.

NGET's response to higher Holding Payment prices

4.25. NGET has advised that as Holding Payment prices increased, it sought to limit the increase in overall frequency response costs through procuring response from alternative sources, and by reducing the overall volume of dynamic response it instructed. Actions taken by NGET in each case are discussed in more detail below.

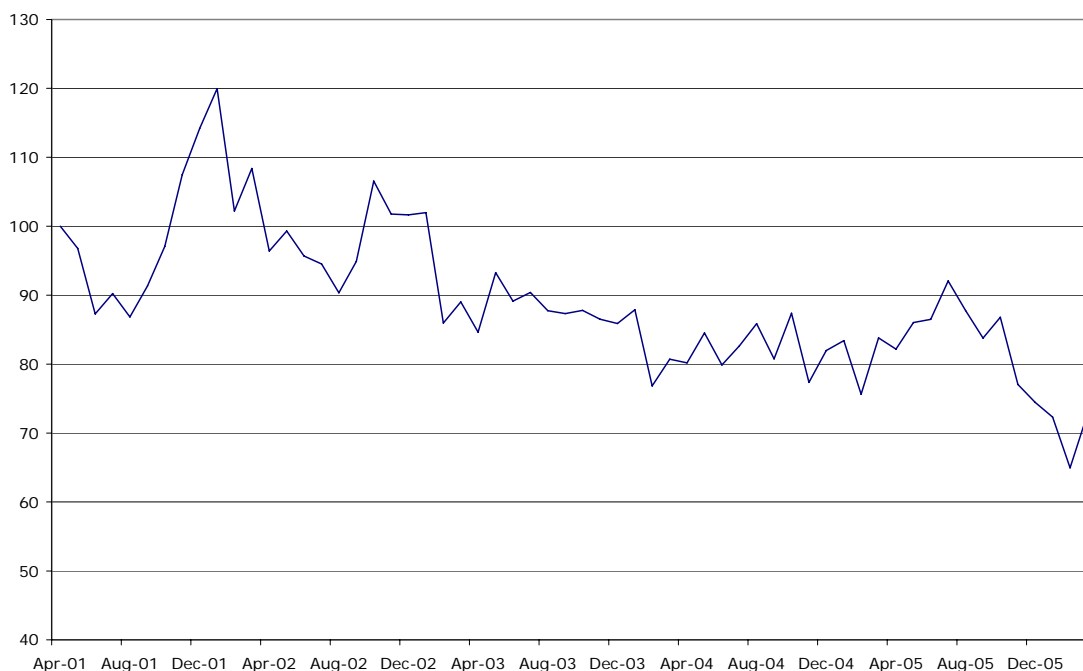
4.26. NGET provided information to us on its procurement of dynamic frequency response from alternative sources, but requested we not disclose this information on the grounds that it was commercially sensitive.

4.27. NGET also indicated that it was able to further minimise the increase in frequency response costs through efficiency gains that reduced the overall volume of frequency response it utilised, including through:

- optimisation of procurement and despatch of frequency response requirements,
- reductions in minimum dynamic frequency requirements, and
- an increase in the available volumes and procurement of non-dynamic response.

4.28. This is illustrated in Figure 4.4, which shows that the total volume of instructed dynamic frequency response has declined significantly following the implementation of CAP047.

Figure 4.4: Total instructed frequency response (April 2001 = 100)



4.29. This data suggests that NGET did take a number of actions regarding the procurement and utilisation of frequency response to minimise the impact of increases in Holding Payment prices on frequency response costs.

Costing methodology

4.30. Finally, we reviewed the methodology NGET used to calculate the amount of its proposed income adjustment. Our initial view is that NGET appears to have adopted a relatively unsophisticated (and arguably overly simplistic) approach in determining the impact of CAP047 on frequency response costs, which hinges on its calculation of the increase in average Holding Payment price(s) that would have occurred in the absence of CAP047.

4.31. NGET's methodology implies that average prices in November 2005 would have been £1.63MW/h in the absence of CAP047. However, average actual prices in October 2005 were already £1.75MW/h (as previously discussed). The last time these prices were at, or below, £1.63MW/h was in April 2005, before the most recent triennial price review under the pre-CAP047 price setting approach. We do not consider it likely that prices in November 2005 would have returned to that level.

Possible alternative methodology

4.32. We propose that, rather than use NGET's methodology to determine the level of Holding Payment prices that would have been observed in the absence of CAP047 in November 2005 to March 2006, it is appropriate to adopt an alternative methodology.

4.33. We believe that in the absence of CAP047, Holding Payment prices in November would, more likely than not, have continued to trend forward from £1.75MW/h in October 2005, rather than have fallen to £1.63MW/h as occurs under NGET's analysis.³⁷

4.34. Therefore, we 'uplifted' the profile of NGET's prices to align with actual pre-CAP047 prices. We also considered that Holding Payment prices may, on average, have stabilised at £1.75MW/h, their October 2005 level. We believe this establishes the most likely upper and lower bounds for Holding Payment prices had CAP047 not been implemented. The implications for the total estimated cost is shown in Table 4.1.

Table 4.1: Estimated additional mandatory frequency response procurement costs post-CAP047

Month	Response Volume (GWh)	National Grid		Ofgem 'Flatline'		Ofgem 'Profiled'	
		Price (£/MW/h)	Total Cost (£m)	Price (£/MW/h)	Total Cost (£m)	Price (£/MW/h)	Total Cost (£m)
Nov	1204	1.628	1.823	1.75	1.681	1.75	1.676
Dec	1140	1.672	1.780	1.75	1.695	1.79	1.640
Jan	1104	1.699	1.685	1.75	1.633	1.82	1.550
Feb	1005	1.642	2.127	1.75	2.022	1.76	2.004
Mar	1139	1.62	3.576	1.75	3.433	1.74	3.438
Total			10.99		10.46		10.31

³⁷ This is the average October Holding Payment price advised by NGET after correcting for the despatch error resulting from a new frequency response provider being despatched on indicative contract prices, but settled at higher final contract prices, which had not been updated in NGET's despatch file.

4.35. Using the same methodology, we estimated that firm frequency response costs increased by £1.86 million under the 'flatline' approach or £1.83 million under the 'profiled approach'.

Summary of Ofgem's views

4.36. While an increase in frequency response procurement costs following the implementation of CAP047 was foreseeable, the increase was probably larger than we anticipated. This may in part be because the Response Energy Payment component of mandatory frequency response continued to be established administratively.

4.37. Our initial view is that NGET's costing methodology is likely to overstate the increase in frequency response costs following the implementation of CAP047 as it understates what Holding Payment prices are likely to have been in November 2005 to March 2006 in the absence of CAP047.

Summary

4.38. This chapter has looked at issues related to the procurement of frequency response by NGET that we consider are relevant in determining whether NGET has acted economically and efficiently in minimising frequency response costs following the implementation of CAP047, and in determining whether any or all of its proposed income adjustment should be allowed. We have set out our initial views and posed a series of questions on which we are particularly interested in gaining the views of interested parties.

4.39. In the next chapter, we briefly summarise our next steps.

5. Next steps

Chapter Summary

This chapter briefly summarises our next steps.

Question box

There are no specific questions in this chapter.

5.1. As noted in Chapter 1, NGET's transmission licence requires that, once we have received notice of a proposed IAE, and after consultation with NGET and users, we must determine within three months:

- whether any or all of the costs and/or expenses given in a notice resulted from an IAE,
- whether the proposed IAE has increased (or decreased) NGET's costs by more than £2 million, and
- if so, whether the amount of the proposed income adjustment ensures that the financial position and performance of NGET is, insofar as is reasonably practicable, the same as if that IAE had not taken place, and if not, what allowed income adjustment would secure that effect.

5.2. The purpose of this document has been to outline issues related to each of NGET's two proposed IAEs to analyse whether NGET has acted economically and efficiently in minimising the cost of managing internal to Scotland and Cheviot constraints following the start of BETTA, and frequency response following the implementation of CAP047.

5.3. With respect to each, we have set out our initial views and posed a series of questions on which we are particularly interested in gaining the views of interested parties. We will consider each independently, and make two separate final determinations. Interested parties may provide feedback to us on either or both of NGET's proposed IAEs.

5.4. For avoidance of doubt, the Authority's discretion to determine the amount of income adjustment is unfettered by this consultation paper. The determined income adjustment may be any amount from nil to the full amount proposed by NGET.

5.5. Responses should be sent to wholesale.markets@ofgem.gov.uk, to be received no later than **1 September 2006**. Further details of how to respond can be found in Appendix 1. We expect to publish our determination on each of NGET's proposed IAEs, including the amount of any allowed income adjustment by **29 September 2006** after considering the views provided by interested parties to this consultation.

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Appendix 1 - Consultation Response and Questions

1.1. Ofgem would like to hear the views of interested parties in relation to any of the issues set out in this document. In particular, we would like to hear from Scottish generators and transmission companies.

1.2. We would especially welcome responses to the specific questions which we have set out at the beginning of each chapter heading and which are replicated below.

1.3. Responses should be received by **1 September 2006** and should be sent to:

Sonia Brown
Director, Wholesale Markets
Ofgem
9 Millbank
London
SW1P 3GE

wholesale.markets@ofgem.gov.uk

1.4. Unless marked confidential, all responses will be published by placing them in Ofgem's library and on its website www.ofgem.gov.uk. Respondents may request that their response is kept confidential. Ofgem shall respect this request, subject to any obligations to disclose information, for example, under the Freedom of Information Act 2000 or the Environmental Information Regulations 2004.

1.5. Respondents who wish to have their responses remain confidential should clearly mark the document/s to that effect and include the reasons for confidentiality. Respondents are asked to put any confidential material in the appendices to their responses. It would be helpful if responses could be submitted both electronically and in writing.

1.6. Having considered the responses to this consultation, Ofgem intends to make a determination as to whether the events or circumstance that are the subject of this consultation paper are IAEs, and if so, the amount of any income adjustment that should be allowed.

1.7. Any questions on this document should, in the first instance, be directed to:

Corey Dykstra
Wholesale Markets
Ofgem
9 Millbank
London
SW1P 3GE
020 7901 7149
corey.dykstra@ofgem.gov.uk

CHAPTER: One

There are no specific questions in this chapter.

CHAPTER: Two

There are no specific questions in this chapter.

CHAPTER: Three

Question 1: Do you consider that, prior to the start of the 2005/06 SO incentive period and based on available information at the time, NGET acted economically and efficiently in deciding to manage internal to Scotland and Cheviot constraints in the BM?

Question 2: Do you have any comments on whether the analysis we present in relation to forecasting the level of self-despatch of generation is appropriate in addressing this issue?

Question 3: Do you consider that, in November 2005, NGET acted economically and efficiently in managing internal to Scotland constraints through a commercial contract?

Question 4: Do you consider that NGET acted economically and efficiently in negotiating this contract?

Question 5: Do you have any comments on the methodology used by NGET in estimating the total cost of managing internal to Scotland and Cheviot constraints following the start of BETTA, and the amount of the proposed income adjustment?

Question 6: Do you have a view on the appropriateness of having separate cost allowances within the overall SO incentive scheme cost target?

CHAPTER: Four

Question 1: Do you agree that NGET has acted economically and efficiently in procuring frequency response to minimise costs?

Question 2: Do you have any comments on the methodology used by NGET in estimating the total cost of procuring frequency response following the implementation of CAP047, and the amount of the proposed income adjustment?

Question 3: Do you have any comments on our proposed alternative methodology, and the amount of the income adjustment that may result should we determine that the events or circumstances surrounding the increase in frequency response costs incurred by NGET is an IAE?

Question 4: Do you have a view on the appropriateness of having separate cost allowances within the overall SO incentive scheme cost target?

CHAPTER: Five

There are no specific questions in this chapter.

Appendix 2 – IBC component breakdown

Calculating IBC for the SO incentive scheme

1.1. NGET is the System Operator (SO) for the entire Great Britain (GB) transmission system. In its role as SO, NGET is responsible for system balancing and energy balancing. These roles are defined below:

- **system balancing:** NGET must ensure that the system remains within safe operating limits by managing the level of electricity generated and the level of demand observed, consistent with any transmission related constraints, and
- **energy (or electricity) balancing:** NGET must undertake the residual purchasing and selling of electricity to keep the transmission system in energy balance in real time.

1.2. In carrying out these roles, NGET incurs costs. These balancing costs are recovered from market participants and ultimately customers.

1.3. As part of this cost recovery process the Authority sets SO incentive schemes, which provide NGET with commercial incentives to operate the system in an economic, efficient and coordinated manner. For this reason, the balancing costs that NGET incurs throughout the incentive scheme period and then recovers can be thought of as Incentivised Balancing Costs (IBC).

1.4. In designing these incentive schemes, the Authority sets a target IBC for the incentive period and if actual IBC are below this target, NGET keeps a proportion of the reduction in costs as an incentive payment. If actual IBC are above this target, NGET bears a proportion of the costs in excess of the target. NGET's overall gains or losses are limited by a cap on payments and a floor on losses.

1.5. As a first step in developing this IBC target and other incentive scheme parameters it is necessary for NGET to provide Ofgem with a projection of the balancing costs it anticipates incurring over the incentive period ie. its projected IBC. NGET's projected IBC are considered carefully by the Authority during the development of the SO incentive scheme.

1.6. NGET's SO incentive scheme reward or penalty is determined by its actual IBC at the end of the incentive period relative to the target amount determined by the Authority, and other scheme parameters.

Costs included in the IBC

1.7. The costs which are included in NGET's IBC can be illustrated as follows:

$$\text{IBC} = \text{CSOBM} + \text{BSCC} + \text{TLA} - \text{NIA} - \text{OM} - \text{RT}$$

where the various terms are defined as follows:

- **CSOBM (Daily System Operator Balancing Mechanism Cashflow)** - the cost of bids and offers in the Balancing Mechanism (BM) accepted in the relevant period, less the total non-delivery charge³⁸ for that period,
- **BSCC (Balancing Services Contract Costs)** - the cost of contracts for the availability or use of balancing services, excluding costs within CSOBM (but including charges made by the licensee for the provision of balancing services to itself), i.e. this component consists of all costs of balancing services not procured through the Balancing Mechanism,
- **TLA (Transmission Loss Adjustment)** - the volume of transmission losses multiplied by the Transmission Losses Reference Price (TLRP) for each Settlement Period, summed across all Settlement Periods,
- **NIA (Net Imbalance Adjustment)** - the total net imbalance volume (NIV) multiplied by the Net Imbalance Volume Reference Price (NIRP) for each Settlement Period, summed across all Settlement Periods. NIA is deducted from CSOBM to reflect the fact that NGET has little control over the extent to which participants choose not to balance their positions,
- **OM** - which is revenue from the provision of balancing services to others during the relevant incentive period, and
- **RT** - the amount of any allowed income adjustment during the relevant incentive period.

1.8. Ordinarily, the last 2 terms have a zero value. It is through the last component, RT, that an income adjustment resulting from an IAE would be factored into IBC. RT is subtracted from the IBC calculation, therefore, an income adjustment assigned a positive value will lead to a reduction in IBC, and vice versa.

³⁸ Non-delivery charges relate to payments as a result of participants failing to deliver Balancing Mechanism bids or offers that have been accepted by NGET.

Appendix 3 – NGET transmission licence provisions

The consequences of an IAE for IBC

1.1. In its role as SO, NGET is subject to an SO incentive scheme to ensure the transmission system is operated in an economic, efficient and coordinated manner.

1.2. The target IBC and associated scheme parameters set by the Authority as part of this incentive scheme, and NGET's actual incurred IBC, jointly determine NGET's profit or loss from its SO activities for the incentive period.

1.3. In addition, there are provisions in the electricity transmission licence for NGET to raise an IAE, which may impact upon NGET's final profit / loss position. If an IAE is raised and the Authority determines that an IAE did occur during the incentive period, then additional costs which were not accounted for at the time of setting the IBC target can be recovered by NGET in due course.

The IAE provisions in the licence

1.4. The IAE provisions are intended to provide protection for both NGET and transmission system users in case an event or set of circumstances occur that result in costs or savings accruing to NGET in connection with its SO activities that were not envisaged at the time that the SO incentive scheme was agreed.

1.5. The IAE provisions are detailed in special condition (SC) AA5A part 2(i) paragraph 10-12 of NGET's transmission licence. This SC outlines what constitutes an IAE, and the processes that must be followed by all relevant parties in giving notice of a proposed IAE and making a determination on the proposed IAE.

1.6. The relevant sections of the licence are summarised below. The IAE assessment process is illustrated diagrammatically in Figure A3.1.

1.7. Special Condition AA5A: Revised Restrictions on Revenues

Paragraph 10

Income adjusting events under the balancing services activity revenue restriction on external costs

- (a) An income adjusting event may arise from any of the following:
 - (i) an event or circumstance constituting force majeure under the BSC;

-
- (ii) an event or circumstance constituting force majeure under the CUSC;
 - (iii) a security period as defined in special condition AA5D; and
 - (iv) an event or circumstance other than listed above, which is, in the opinion of the Authority, an income adjusting event and is approved by it as such in accordance with paragraph 12 of this special licence condition AA5A.

where the event has, for relevant year t, increased or decreased the value of IBCt by more than £2,000,000 (the "threshold amount"). This threshold does not apply in respect of sub-paragraph 10(a)(iii) above.

For the purpose of relevant year t commencing on 1 April 2005 and ending on 31 March 2006, events or circumstances arising directly from the implementation or otherwise of the proposed amendments and modifications listed in tables 1 and 2 of Special Condition AA5a shall not qualify as an income adjusting event for the purpose of paragraph 10(a) above.

Paragraph 11

Notice of proposed income adjusting event

(a) Where the licensee considers, and can provide supporting evidence that, in respect of relevant year t, there have been costs and/or expenses that have been incurred or saved by an income adjusting event, then the licensee shall give notice of this event to the Authority.

(b) Where any other Party (as defined in the BSC) considers, and can provide supporting evidence thereof, that, in respect of relevant year t, there have been costs and/or expenses that have been incurred or saved by an income adjusting event, then that Party may give notice of this event to the Authority.

A notice provided to the Authority under paragraphs 11(a) and 11(b) shall, in the case of the licensee, and should, in so far as is practicable in the case of any other Party, give particulars of:

- (i) the event to which the notice relates and the reason(s) why the person giving the notice considers this event to be an income adjusting event;
- (ii) the amount of any change in costs and/or expenses that can be demonstrated by the person giving the notice to have been caused or saved by the event and how the amount of these costs and/or expenses has been calculated;
- (iii) the amount of any allowed income adjustment proposed as a consequence of that event and how this allowed income adjustment has been calculated; and
- (iv) any other analysis or information which the person submitting the notice considers to be sufficient to enable the Authority and the relevant parties to fully assess the event to which the notice relates.

If the Authority considers that the analysis or information provided in subparagraphs 11(c)(i) to 11(c)(iv) above is insufficient to enable both the Authority and the relevant parties to assess whether an income adjusting event has occurred and/or the amount of any allowed income adjustment that should be approved, the Authority can request that the supporting evidence be supplemented with additional information that it considers appropriate.

A notice of an income adjusting event shall be given as soon as is reasonably practicable after the occurrence of the income adjusting event, and, in any event, not later than three months after the end of the relevant year in which it occurs.

The Authority will make public, excluding any confidential information, of any income adjusting event following its receipt.

Any notice submitted to the Authority under either subparagraphs 11(a) or 11(b) above should clearly identify whether any of the information contained in the notice is of a confidential nature. The Authority shall make the final determination as to confidentiality having regard to:

the need to exclude from disclosure, so far as is reasonably practicable, information whose disclosure the Authority considers would or might seriously prejudicially affect the interests of a person to which it relates; and

(ii) the extent to which the disclosure of the information mentioned in subsection 11(g)(i) is necessary for the purposes of enabling the relevant parties to fully assess the event to which the notice relates.

Paragraph 12

The Authority's determination

(a) Following consultation with relevant Parties, including the licensee, BSC parties and CUSC parties, the Authority shall determine:

(i) whether any or all of the costs and/or expenses given in a notice pursuant to paragraph 11(a) or 11(b) were caused or saved by an income adjusting event;

(ii) whether the event or circumstance has increased or decreased the value of IBCt by more than the threshold amount, save in the case of paragraph 10(a)(iii) where the threshold amount shall not apply; and

(iii) if so, whether the amount of the proposed income adjustment ensures that the financial position and performance of the licensee are, insofar as is reasonably practicable, the same as if that income adjusting event had not taken place, and if not, what allowed income adjustment would secure that effect.

(b) In relation to the relevant year t , the allowed income adjustment RT_t shall be:

(i) the value determined by the Authority under paragraph 12(a); or

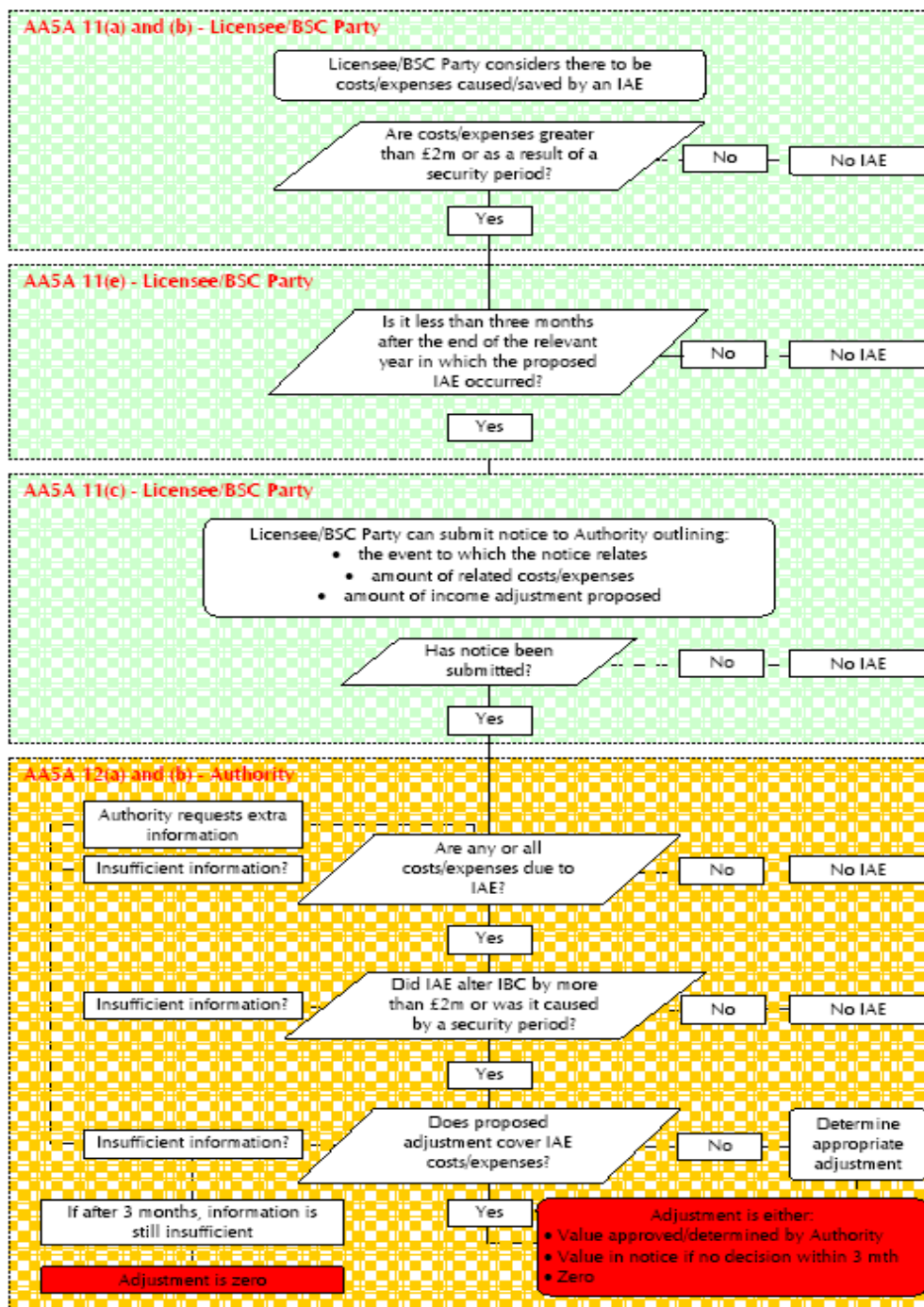
(ii) if the Authority has not made a determination under paragraph 12(a) within three months of the date on which notice of an income adjusting event was provided to the Authority, the amount of the allowed income adjustment proposed as a consequence of the event in the notice given to the Authority under sub-paragraph 11(c)(iii); or

(iii) in all other cases zero, including situations where the Authority has not made a determination under paragraph 12(a) above within three months of the date on which notice of an income adjusting event was provided to the Authority and the Authority has, before the end of that three month period, informed the relevant parties that the Authority considers that the analysis of information provided in accordance with paragraphs 11(c) and/or 11(d) is insufficient to enable the Authority and relevant parties to assess whether an income adjusting event has occurred and/or the amount of any allowed income adjustment.

(c) The Authority's decision in relation to any notice given under paragraph 11(a) or paragraph 11(b) shall be in writing, shall be copied to the licensee and shall be in the public domain.

(d) The Authority may revoke an approval of an income adjusting event and allowed income adjustment with the consent of the licensee, following consultation with the licensee and relevant parties. Revocation of any income adjusting event and allowed income adjustment shall be in writing, shall be copied to the licensee and shall be in the public domain.

Figure A3.1



Appendix 4 - Ofgem's formal information request



Duncan Burt
Regulatory Policy Manager
National Grid plc
NGT House
Warwick Technology Park
Gallows Hills
Warwick
CV24 6DA

*Promoting choice and
value for all customers*

Your Ref:
Our Ref:
Direct Dial: 020 7901 7149
Email: sonia.brown@ofgem.gov.uk

18 July 2006

Dear Duncan,

**NGET's External System Operator incentive scheme 2005/06:
Request for information under paragraph 11(d) of Special Condition AA5A of
National Grid Electricity Transmission plc's Transmission Licence**

I refer to National Grid Electricity Transmission's (NGET's) letter of 30 June 2006 and the accompanying notices advising that NGET has incurred costs in 2005/06 as a result of events or circumstances that it considers are income adjusting events (IAEs).

In order for Ofgem¹ to effectively assess these notices, NGET is required to provide it with additional information concerning the proposed IAEs, as outlined in the appendix to this letter. The Authority is requesting this information pursuant to Special Condition AA5A Part 2(i), paragraph 11(d) of NGET's transmission licence.

Please can the information requested, other than as follows, be provided to Ofgem by **5:00pm on Tuesday 25 July 2006** via email to coray.dykstra@ofgem.gov.uk. Information requested by points a, b and c under the sub-heading 'Accuracy of NGET's assumptions in its original forecasts' in the appendix, are similarly to be provided to Ofgem by **5:00pm on Friday 28 July 2006**.

This timeframe is designed to support the Authority to make a determination on the amount of any income adjustment that should be allowed within three months of the date on which notice of the proposed IAEs was provided by NGET.

¹ Ofgem is the Office of the Gas and Electricity Markets, which supports the Gas and Electricity Markets Authority (the "Authority"), the regulator of the gas and electricity industries in Great Britain. Ofgem's primary aim is to bring choice and value to all gas and electricity customers by promoting competition and regulating monopolies. The Authority was established by the Utilities Act 2000 and its powers are provided for under the Gas Act 1986, the Electricity Act 1989, the Competition Act 1998, the Utilities Act 2000, the Enterprise Act 2002 and the Energy Act 2004. The terms "Ofgem", "we" and "the Authority" are used interchangeably in this letter.

The Office of Gas and Electricity Markets 9 Millbank London SW1P 3CETel 020 7901 7000 Fax 020 7901 7066 www.ofgem.gov.uk

You will appreciate that this request for information is without prejudice, and further information may be required from NGET in future. For example, we have already agreed that we may seek details of submitted bid/offer volumes and prices on specific days after we analyse the detailed breakdown of costs incurred in relation to individual Cheviot and internal Scotland constraints, which will be provided by NGET under this information request.

Please feel free to contact Corey Dykstra (020 7901 7149) if you would like to discuss any aspect of this letter or its attachment further.

Yours sincerely



Sonia Brown
Director, Wholesale Markets

Appendix

Information request for the Authority's monitoring of NGET's external balancing costs (2006/07)

The following information concerning the events or circumstances in relation to each of the two notices submitted by NGET under Special Condition (SC) AA5A Part 2(i), paragraph 11 of its transmission licence is necessary to enable the Authority to determine whether the amount of the income adjustment proposed by NGET ensures that its financial position and performance is, insofar as is reasonably practicable, the same as if that IAE had not taken place, and if not, what allowed income adjustment would secure that effect.

1. Cheviot constraint (England-Scotland) and internal Scottish constraints

The information we are seeking in relation to the cost of the Cheviot and internal to Scotland constraints fall into three categories: the accuracy of NGET's assumptions in its original forecasts; the actions NGET took to manage Cheviot and internal to Scotland constraints during the 2005/06 SO incentive scheme; and actions NGET has taken since the 2005/06 SO incentive scheme to manage Cheviot and internal to Scotland constraints.

Accuracy of NGET's assumptions in its original forecasts

- a. In producing its original constraint forecasts, NGET made certain assumptions about the Great Britain transmission network, especially in Scotland.

Specific assumptions referred to by NGET were:

- Winter limits of 2200MW, and summer limits of 2000MW under intact conditions and 1200MW under outage conditions for the constraint across the Cheviot boundary;
- 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 were based on those contained in SPTL's April 2004 SYS and SHETL's 2003 SYS;
- The existing operational intertrip schemes within Scotland to continue to be available under BETTA; (e.g. the Ayrshire operational intertrip scheme and the Foyers stability intertrip scheme); and
- No intertrip scheme was available for the Cheviot boundary.

NGET is required to advise Ofgem of the actual outturn in 2005/06 relative to each original assumption. Where there has been a material deviation from its original assumption, NGET must indicate the estimated impact each such deviation had on IBC during 2005/06.

- b. Information is required from NGET as to the actual output (in TWh) in Scotland by type of station during 2005/06.
- c. Information is required from NGET as to the actual transfer (in TWh) across the Cheviot boundary during 2005/06.
- d. Information is required from NGET as to assumptions made in producing its original constraint forecasts on the bid and offer prices that would apply to managing:
 - Cheviot constraints; and
 - Internal Scotland constraints.
- e. Information is required from NGET as to the average cost of constraint management in England and Wales, with representative examples of high, medium and low cost constraints (based on £/MWh).

Actions NGET took to manage Cheviot and internal to Scotland constraints during the 2005/06 SO incentive scheme

- a. Dates, times and duration for all system constraints that are the subject of the proposed IAE.
- b. A detailed breakdown of costs incurred in relation to individual Cheviot and internal Scotland constraints by:
 - Day and relevant settlement period;
 - Whether the constraint was managed through the Balancing Mechanism, or through trades, including for example through a PGBTs or other commercial contract;
 - Daily bid/sell and/or offer/buy volumes (in GWh); and
 - Daily bid/sell and/or offer/buy costs (in £m to 2 decimal places).

For the avoidance of doubt, this information should be similar to that provided in the current Appendix 4. However, the information is to be provided for each settlement period (rather than month), and separately for each constraint (i.e. separately for actions taken to manage a constraints associated with each planned outage, each unplanned outage or under intact conditions).

This means for example that, where constraints arise from more than one planned outage on a single day, the costs associated with managing each constraint should be separately identified.

- c. A full copy of the initial Firm Winter Security Service commercial agreement with Scottish and Southern Energy (SSE), and a full copy of the subsequent new contract agreed on 26 March 2006.
- d. A full copy of any other commercial agreements with SSE relating to the management of Cheviot and/or internal Scottish constraints.
- e. A full copy of any commercial agreements with Scottish Power (SP) relating to the management of Cheviot and/or internal Scottish constraints.

Actions NGET has taken since the 2005/06 SO incentive scheme to manage Cheviot and internal to Scotland constraints

- a. A full copy of any commercial agreements relating to the management of internal Scottish constraints for 2006/07, including the annual commercial agreement for that year with SSE.

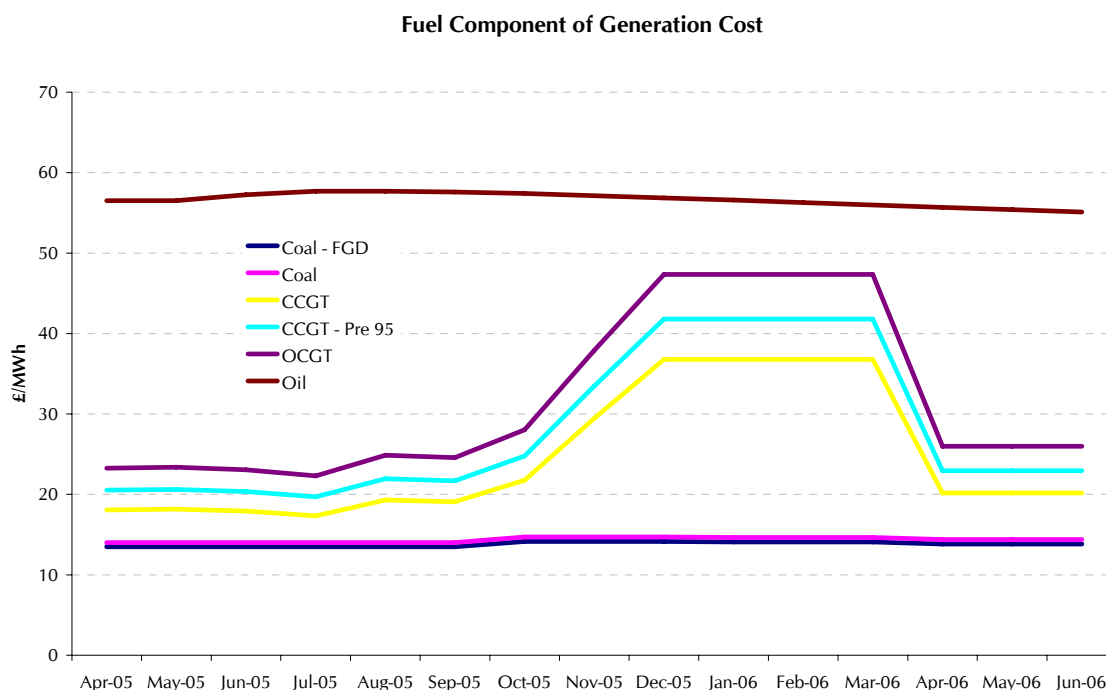
2. Mandatory frequency response (CAP047)

- a. In NGET's notice, Figure 2 provides accepted prices for non-firm dynamic response by month for the period November through to March in 2004/05 and 2005/06. NGET is required to provide the information in this figure for each month in 2004/05 and 2005/06. Energy prices are to be provided in £/MWh to two decimal places.
- b. In NGET's notice, Figure 4 provides the total dynamic response volume by month for the period November through to March in 2004/05 and 2005/06. NGET is required to provide the information in this figure for each month in 2004/05 and 2005/06.
- c. It is unclear whether the analysis in Figure 5 relates to average costs or volume-weighted average costs. NGET is required to recalculate the data in Figure 5 by deriving volume-weighted average prices in each month in 2004/05 and 2005/06.
- d. In NGET's notice, Figure 10 provides the average annual historical holding prices for mandatory dynamic frequency response from 2001/02 to 2005/06. NGET is required to provide this information in a table on a monthly basis for the period 2001/02 to 2005/06. Energy prices are to be provided in £/MWh to two decimal places.
- e. NGET is required to provide the volume of mandatory dynamic frequency response utilised by it on a monthly basis from 2001/02 to 2005/06 in a table.
- f. In NGET's notice, Figures 13 and 14 provides instructed PLR response volume, total PLR payment and effective price for the period November through to March in 2004/05 and 2005/06. NGET is required to provide the information in this figure in a table for each month in 2004/05 and 2005/06. Energy prices are to be provided in £/MWh to two decimal places.

Appendix 5 - Generation despatch forecast

1.1. Figure A5.1 illustrates the fuel cost assumptions we used in estimating forecast generation despatch (in response to peak and average levels of demand in winter 2005/06). This data therefore represents forward prices in April 2005 for the cost of different fuel types in winter 2005/06.

Figure A5.1: Fuel Component of Generation Cost 2005/06



Source: WebICE, Argus and Heren

Appendix 6 - Categorisation of constraint actions

1.1. In calculating the costs associated with managing the internal to Scotland constraints and the Cheviot constraint, NGET first established the 'type' of constraint actions taken throughout the SO incentive scheme period.

1.2. NGET categorises constraint actions into two groups:

- those actions that fall into the energy imbalance part of the Net Imbalance Volume (NIV) price stack (energy actions) or
- those actions that fall into the system part of the NIV price stack (system actions).

1.3. 'Energy' actions do not have an accompanying and opposing balancing action as managing the constraint contributes to the resolution of NIV. 'System' actions on the other hand will have a corresponding and opposing balancing action. This is discussed in more detail below.

Energy actions

1.4. NGET has indicated that only around 3 percent of Scottish constraint actions by cost were categorised as falling in the 'energy' imbalance component of the 'price stack'. In this case, constraint actions contribute to resolving NIV.

1.5. To calculate the net costs of an 'energy' imbalance constraint action, NGET:

- Identifies the volume of the constraint action;
- Identifies the price of the constraint action;
- Calculates a reference price based on submitted prices at gate closure for all plant in England and Wales - this 'unconstrained' cost represents the cost of actions that would have been used to resolve the NIV had the constraint not existed; and
- Derives the price of the constraint action by multiplying the difference between the cost of the constraint action taken and the cost of energy at the NIV reference price for that period by the volume of constraint action taken.

System Actions

1.6. All constraint actions that did not fall within the 'energy' imbalance stack were categorised as 'system' actions.

1.7. To calculate the net costs of an 'system' imbalance constraint action, NGET:

- Identifies the volume of the constraint action;
- Identifies the price of the constraint action;
- Identifies the corresponding replacement price, which is the cost of the actions taken to balance the system in the 'opposite energy direction' to the constraint action - this cost is the volume weighted average of all accepted non-energy balancing prices in the direction of interest; and
- Derives the cost of the constraint action by multiplying the difference between the price of the constraint action taken and the corresponding replacement price by the volume of constraint action taken.

Effect of margin

1.8. From time to time, NGET may take actions to create additional system operating margin. Occasionally, actions taken to manage the Scottish constraints may have displaced actions that NGET might have otherwise taken to create system operating margin.

1.9. NGET sought to identify such instances within the calculation of the net cost of managing the Scottish constraints. To do this, NGET assumed that, in any period where it synchronised units and experienced import constraint issues, any import constraint actions that also synchronised a unit would contribute to system operating margin. To capture this, the cost of the constraint action was discounted by the cost of the alternative action for margin that would have been taken in the absence of the constraint.

1.10. NGET applied this approach to costing both energy and system constraint actions that involved synchronisation of additional units to capture the benefit of the additional operation margin delivered by the constraint action.

1.11. NGET formulated a Margin Reference Price (MRP) from accepted synchronising actions to represent the cost of margin in that period. Only an amount of total period synchronising volume equivalent to the total period constraint volume is used in setting the MRP, where those volumes with the highest priced synchronising actions are included first. A volume weighted average price for these actions was then derived by NGET.

1.12. NGET then calculated the constraint cost in excess of margin cost as the difference between the price of the identified constraint action, and the price that the same volume of margin creation would have cost at the MRP.

Appendix 7 - Recovery of SO operating costs

1.1. NGET recovers costs it incurs in operating the GB transmission system, including SO costs, through Balancing Services Use of System (BSUoS) charges that are paid by transmission system users.

1.2. If approved in full, NGET's proposed income adjustment would reduce the value of the actual IBC used to calculate whether a penalty (or bonus) was due by £35.77 million. As a consequence this would reduce the level of cost incurred by NGET through its SO incentive scheme from around £10 million to £2.8 million. This potential change is illustrated in Table A7.1 below.

Table A7.1 Cost implications of the granting of the IAEs

	No IAEs	IAEs granted in full
Total IBC incurred by NGET	427.20	427.20
Income adjustment for IAEs	0	35.77
SO incentive scheme IBC	427.20	391.43
SO incentive scheme IBC target	377.50	377.50
Target - IBC	-49.70	-13.93
NGET's share through SO incentives (20% downside)	9.94	2.79
Total charge to BSUoS	417.26	424.41

1.3. As highlighted above, in the event that the IAEs were to be granted in full, NGET would be permitted to recover just over £424 million of its SO costs through BSUoS charges. This represents an increase in cost to users of the transmission network of around £7 million.

Process of cost recovery

1.4. While NGET has discretion as to how to apportion the additional costs that it may be permitted to recover from transmission users across the half-hourly BSUoS charges for the year, it has advised that it considers it appropriate to do this in a way that as much as possible reflects the periods in which the IAE costs were incurred.

1.5. In terms of timing, NGET has advised that there are two BSUoS reconciliation 'runs' following the end of the year, the first of which has already occurred for 2005/06 charges, leaving only one final run, which is carried out daily from 14 months after the day in question to June 2007, the end of the reconciliation run. NGET considers that any approved income adjustment would therefore be recovered within this 'final reconciliation' run.

1.6. The IAE process means that any IAE amount would not be confirmed until late September and therefore any amount would be recovered after this date. This would mean that the final reconciliation run had already occurred for approximately the first four months of the 2005/06 year, and hence the reduction in NGET's penalty stemming from any approved income adjustment would need to be recovered across the approximately remaining eight months of the reconciliation run for 2005/06 (ie. October 2006 to June 2007).

Appendix 8 – The Authority's Powers and Duties

1.1. Ofgem is the Office of Gas and Electricity Markets which supports the Gas and Electricity Markets Authority ("the Authority"), the regulator of the gas and electricity industries in Great Britain. This Appendix summarises the primary powers and duties of the Authority. It is not comprehensive and is not a substitute for reference to the relevant legal instruments (including, but not limited to, those referred to below).

1.2. The Authority's powers and duties are largely provided for in statute, principally the Gas Act 1986, the Electricity Act 1989, the Utilities Act 2000, the Competition Act 1998, the Enterprise Act 2002 and the Energy Act 2004, as well as arising from directly effective European Community legislation. References to the Gas Act and the Electricity Act in this Appendix are to Part 1 of each of those Acts.³⁹

1.3. Duties and functions relating to gas are set out in the Gas Act and those relating to electricity are set out in the Electricity Act. This Appendix must be read accordingly⁴⁰.

1.4. The Authority's principal objective when carrying out certain of its functions under each of the Gas Act and the Electricity Act is to protect the interests of consumers, present and future, wherever appropriate by promoting effective competition between persons engaged in, or in commercial activities connected with, the shipping, transportation or supply of gas conveyed through pipes, and the generation, transmission, distribution or supply of electricity or the provision or use of electricity interconnectors.

1.5. The Authority must when carrying out those functions have regard to:

- The need to secure that, so far as it is economical to meet them, all reasonable demands in Great Britain for gas conveyed through pipes are met;
- The need to secure that all reasonable demands for electricity are met;
- The need to secure that licence holders are able to finance the activities which are the subject of obligations on them⁴¹; and

³⁹ entitled "Gas Supply" and "Electricity Supply" respectively.

⁴⁰ However, in exercising a function under the Electricity Act the Authority may have regard to the interests of consumers in relation to gas conveyed through pipes and vice versa in the case of it exercising a function under the Gas Act.

⁴¹ under the Gas Act and the Utilities Act, in the case of Gas Act functions, or the Electricity Act, the Utilities Act and certain parts of the Energy Act in the case of Electricity Act functions.

- The interests of individuals who are disabled or chronically sick, of pensionable age, with low incomes, or residing in rural areas.⁴²

1.6. Subject to the above, the Authority is required to carry out the functions referred to in the manner which it considers is best calculated to:

- Promote efficiency and economy on the part of those licensed⁴³ under the relevant Act and the efficient use of gas conveyed through pipes and electricity conveyed by distribution systems or transmission systems;
- Protect the public from dangers arising from the conveyance of gas through pipes or the use of gas conveyed through pipes and from the generation, transmission, distribution or supply of electricity;
- Contribute to the achievement of sustainable development; and
- Secure a diverse and viable long-term energy supply.

1.7. In carrying out the functions referred to, the Authority must also have regard, to:

- The effect on the environment of activities connected with the conveyance of gas through pipes or with the generation, transmission, distribution or supply of electricity;
- 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 that appear to it to represent the best regulatory practice; and
- Certain statutory guidance on social and environmental matters issued by the Secretary of State.

1.8. The Authority has powers under the Competition Act to investigate suspected anti-competitive activity and take action for breaches of the prohibitions in the legislation in respect of the gas and electricity sectors in Great Britain and is a designated National Competition Authority under the EC Modernisation Regulation⁴⁴ and therefore part of the European Competition Network. The Authority also has concurrent powers with the Office of Fair Trading in respect of market investigation references to the Competition Commission.

⁴² The Authority may have regard to other descriptions of consumers.

⁴³ or persons authorised by exemptions to carry on any activity.

⁴⁴ Council Regulation (EC) 1/2003

Appendix 9 - Glossary

B

Balancing and Settlement Code (BSC)

The legal document setting out the rules for the operation and governance of the Balancing Mechanism and imbalance settlement. All licensed electricity generators and suppliers must sign up to the BSC and other interested parties may also choose to do so.

Balancing Mechanism (BM)

This is the mechanism which the SO utilises between gate closure and the settlement period as a tool for adjusting levels of generation and demand (energy balancing) and also to ensure that the pattern of generation and demand is consistent with any system transmission constraints (system balancing). During BM timescales, the SO buys and sells electricity (normally from generators and suppliers who voluntarily place their bids and offers).

Balancing Mechanism Units (BMUs)

Individual generation units and supply points that participate in the balancing mechanism. Note that there might be several generation units within a generation plant.

Balancing Services Use of System (BSUoS) charges

The daily charge levied on users of the transmission system in order to recover the costs of operating the transmission system and procuring and utilising balancing services.

British Electricity Trading and Transmission Arrangements (BETTA)

The BETTA reforms, introduced on 1 April 2005, created a single, competitive wholesale electricity trading market in Great Britain. These trading arrangements are based upon the preceding England and Wales trading arrangements. The BETTA arrangements allow parties to trade energy forward through bilateral over the counter trades, through exchanges, or in any other manner they deem appropriate on a GB basis.

C

Connection and Use of System Code (CUSC)

This legal document 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.

D

Demand tripping scheme

As an alternative to generation support, in certain situations the system voltage can be secured and the transmission system constraint resolved through the use of automatic demand tripping. This has the effect of reducing the demand in the constrained area to a level below that which would cause voltages to deviate outside limits.

F

Fast reserve

This is the fast provision of reliable power via increased generation or reduction in demand which can be provided within 2 minutes, at a delivery rate of $\geq 25\text{MW/minute}$ and the reserve needs to be sustainable for 15 minutes. Entered into via a tender process.

Frequency response

NGET has a statutory duty to maintain system frequency between $\pm 1\%$ of 50 Hz. System frequency is managed by NGET on a second-by-second basis through the procurement of a variety of Balancing Services. The common characteristic of all 'Frequency management' services is the automatic provision of load regulation (generation or demand) in response to a change in system frequency.

The provision of Frequency Response is classified as either Dynamic or Non-Dynamic. Dynamic Frequency Response is the continuous regulation of load in response to changes in system frequency. Non-dynamic (Static) Frequency Response is the automatic provision of a change in load by frequency initiated relay, ie. the load step change is automatically triggered as the frequency passes through the relay threshold.

The capability to provide Dynamic Frequency Response is a mandatory requirement placed on all licensed generators, ie. mandatory Frequency Response. Non-mandatory (or commercial) Frequency Response is entered into between the SO and the relevant provider, with the provider being able to freely price for volume.

In sum, frequency response can be procured through a variety of mechanisms

Dynamic

- Generator mandatory Frequency Response
- Generator commercial (non-mandatory) Frequency Response
- Firm Frequency Response Tender

Non-Dynamic

- Demand side frequency response by frequency initiated relay
- Firm Frequency Response Tender

G

Gate Closure

The point in time when bilateral trading stops and the Balancing Mechanism is in operation. Currently gate closure is set at 1 hour before each settlement period.

I

Income Adjusting Event (IAE)

An income adjusting event (IAE), as defined in special condition AA5A part 2(i) paragraph 10-12 of NGET's transmission licence, may arise from any of the following:

- (i) an event or circumstance constituting force majeure under the BSC;
- (ii) an event or circumstance constituting force majeure under the CUSC;
- (iii) a security period as defined in special condition AA5D; and
- (iv) an event or circumstance other than listed above, which is, in the opinion of the Authority, an income adjusting event and is approved by it as such in accordance with paragraph 12 of special licence condition AA5A.

To be an IAE, the income adjusting event, for relevant year t , must increase or decrease the value of IBC t by more than £2,000,000. This threshold does not apply in respect of sub-paragraph (iii) above.

Intertrip

The majority of intertrips are required to strategically manage power flows on the system, and remove at short notice potentially vulnerable circuits. Commercial intertrips are negotiated bilaterally, whilst operational intertrips are covered by the CAP076 provisions (administered arrangements).

R

Reactive Power

Power generation creates background energy which absorbs or generates reactive energy as a result of the creation of magnetic and electric fields. Reactive power needs to be provided to assist in balancing the system and retaining its integrity. Market agreement and default arrangements cover the provision of mandatory services.

Reserve Contracts

This is one of the ways in which the SO can keep actual demand and supply balanced (energy/electricity balancing) or solve the constraints in the system (system balancing). Contracts are entered into by the SO with generators or suppliers to hold a reserve. The costs of these contracts are fed into the energy imbalance price. They normally have the form of option fee contracts.

S

Sharing factors

These describe the percentage of profit or loss NGET will be subjected to if the day to day costs of running the system fall below or exceed the target cost.

Standing reserve

NGET's requirement for standing reserve can be met from synchronised and non-synchronised plant. The response time must be within 20 minutes, for a delivery of at least 3MW and needs to be maintained for at least 2 hours if instructed. Contracts struck via open tender.

System Operator (SO)

The entity responsible for operating the high voltage electricity transmission system and keeping supply and demand balance within safe technical limits. Consequently, it acts as a residual balancer and resolves constraints on the transmission system. National Grid Electricity Transmission (NGET) acts as the SO for GB.

T

Transmission system constraints

Transmission system constraints occur when actual power flows across the network must be altered to ensure that the system is operated in accordance with standards laid out in the Great Britain Security and Quality of Supply Standards (GBSQSS). These standards are designed to ensure there is sufficient redundancy in the system to manage contingencies such as transmission equipment or generator faults, or breakdowns such that, following a fault or under steady-state conditions, system security is maintained.

Appendix 10 - Feedback Questionnaire

1.1. Ofgem considers that consultation is at the heart of good policy development. We are keen to consider any comments or complaints about the manner in which this consultation has been conducted. In any case we would be keen to get your answers to the following questions:

1. Do you have any comments about the overall process, which was adopted for this consultation?
2. Do you have any comments about the overall tone and content of the report?
3. Was the report easy to read and understand, could it have been better written?
4. To what extent did the report's conclusions provide a balanced view?
5. To what extent did the report make reasoned recommendations for improvement?
6. Please add any further comments?

1.2. Please send your comments to:

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