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# National Grid Electricity Transmission and National Grid Gas System Operator Incentives from 1 April 2007

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Target audience: This document will be of interest to generators, shippers, 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), while National Grid Gas plc (NGG) is the SO for the gas transportation system. Each is required to act in an efficient, economic and co-ordinated manner in performing its respective SO role. To encourage this, we develop incentive schemes with specific cost targets, and sharing factors where actual costs deviate from the target.

This document sets out initial forecasts of SO costs from 1 April 2007 provided to us by NGET and NGG, our preliminary views on these forecasts, and invites feedback from interested parties on a number of questions set out in this document.

NGET and NGG's forecasts, and feedback to this consultation, will assist us in developing our initial proposals for incentive schemes to apply to each SO from 1 April 2007.

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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. National Grid Gas plc (NGG) is the SO for the gas National Transmission System (NTS) in GB and has responsibility for the residual balancing activity on the NTS.

We develop SO incentive schemes that are designed to encourage NGET and NGG to operate the electricity and gas transmission system respectively in an efficient and economic manner, and to effectively manage the costs of operating each system. These costs are borne by transmission system users and, ultimately, by electricity and gas consumers.

This document sets out the initial forecasts of SO costs from 1 April 2007 provided by NGET and NGG. We also provide our preliminary views on these forecasts, and invite feedback from interested parties on the questions set out in this document.

## Associated Documents

- Ofgem's Transmission Price Control Review: Updated Proposals (Reference 170/06)

http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/16828_060922_Maindocument.pdf

- Ofgem's Potential income adjusting events under NGET's 2005/06 system operator incentive scheme (Reference 135/06)

http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/16029_135_06.pdf?wtfrom=/ofgem/whats-new/archive.jsp

- Ofgem's December letter: National Grids Electricity Transmission System Operator Incentives 2006-07 and associated appendices.

http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/13412_Initial_proposals_letter_FINAL_corrected_.pdf

- Ofgem's Final proposals and impact assessment: Transmission price control and BETTA - 'December 2004' (Reference 279/04).

http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/9612_27904.pdf?wtfrom=/ofgem/whats-new/archive.jsp

- Ofgem Final proposals: Extending National Grid Electricity plc's transmission Owner Control for 2006/07 - 'November 2005'.

http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/12992_253_05.pdf?wtfrom=/ofgem/whats-new/archive.jsp

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# Summary

The primary purpose of this document is to invite comments from interested parties on initial forecasts of system operator (SO) costs that National Grid Electricity Transmission plc (NGET) and National Grid Gas plc (NGG) expect to incur in 2007/08 (and up until 2011/12 in the case of internal costs).

## Background

NGET and NGG, both subsidiaries of National Grid plc, are respectively the SO of the Great Britain (GB) high voltage electricity transmission network and the national gas transmission system. Under their respective transmission and transporter licences each is responsible for ensuring the systems stay in balance, and are operated within safe technical and operating limits.

We develop SO incentive schemes to encourage NGET and NGG to undertake its SO role in an efficient and economic manner, and to effectively manage the costs of operating the electricity and gas transmission systems as these SO costs are borne by system users and, ultimately, by electricity and gas consumers. There is currently no external cost SO incentive scheme in electricity.[1] The incentive schemes for gas external costs and both gas and electricity internal costs are due to expire on 31 March 2007.

## NGET's and NGG's SO cost forecasts

For electricity, NGET has forecast that external SO costs in 2007/08 will reach £483 million, compared with £428 million in 2005/06. NGET also forecasts it will incur operating expenditure (opex) totalling £251.5 million and capital expenditure (capex) of £47 million for the five-year period from 2007/08 to 2011/12.

For gas, NGG has forecast that its gas cost (shrinkage) volume and gas reserve volume requirements for 2007/08 will be 7,750GWh and 1,589GWh respectively (central case projections). Internal SO costs for the five-year period from 2007/08 to 2011/12 are forecast to comprise opex totalling £126.4 million and capex of £64.4 million.

## Ofgem's preliminary views

For electricity we are proposing an external SO incentive scheme for 12 months (from 1 April 2007), which retains a single cost target, although we may consider some form of indexation to **wholesale** electricity prices. For the internal scheme,

[1] For further information, refer to Chapter 2.

we are proposing separate opex and capex targets that run for a five year period to 31 March 2012 - consistent with the duration of the transmission price control.

For gas, the external SO incentive scheme would also be for 12 months, with the existing external framework of separate targets for system balancing and residual balancing, and information provision. The duration, scope and form of the internal scheme would be the same as that for electricity.

We expect to establish initial proposals outlining options for scheme targets, sharing factors, and caps and collars in our initial proposals consultation to be published in December 2006. These proposals will be informed by NGET's and NGG's forecasts of SO costs, on which we are now inviting feedback.

With respect to NGET's forecasts, our preliminary view is that there are good prospects for the actual overall level of external SO costs to be less than its initial forecast due to falling wholesale electricity prices and recent rule changes. In terms of NGET's forecast of internal SO costs, we consider that the efficient level of opex that should be incurred by NGET over the duration of the incentive is £227.6 million, which is £24 million below NGET's forecast. In terms of capex, our preliminary view is that the efficient level of capex is £41 million, which is £6 million below NGET's forecast.

In relation to NGG's external SO incentives, we consider that there is scope for the reductions from NGG's forecast, particularly on shrinkage volumes. In terms of NGG's internal SO costs for the period 2007/08 to 2011/12, our preliminary view is that opex of £122.1 million is appropriate, while an efficient level of capex would be £41.5 million, £22.7 million below NGG's forecast.

As part this consultation we are also asking for respondents views on whether income adjusting events (IAEs) should be part of an SO incentive scheme in both gas and electricity. This is in response to some concerns that were raised by respondents' as part of the recent consultation on IAEs in electricity for the incentive scheme that covered 2005/6.[2]

## Next steps

Having reviewed NGET and NGG's forecasts, we are now consulting on these estimates of SO costs prior to developing our initial proposals for the electricity and gas incentive schemes. This will provide interested parties with an opportunity to comment on a key input to the development of targets for the SO incentive schemes. We will consider feedback we receive to this consultation, plus any subsequent NGG and NGET forecasts, in developing our initial proposals setting out SO cost and performance targets, sharing factors, caps and collars. We will publish a consultation paper outlining our initial proposals, and inviting feedback from interested parties, in December 2006.

[2] Refer to Ofgem's Determination letter of 25 September 2006 (Reference 171/06) http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/16856_171_06.pdf

# 1. Introduction

**Chapter Summary**

This chapter provides a short overview of the system operation (SO) roles in electricity and gas, and outlines the process we intend to follow in developing SO incentive schemes for NGET and NGG to apply from 1 April 2007. It also provides an outline of the structure of this document and the way forward.

**Question box**

There are no specific questions in this chapter.

## Background

1.1. National Grid Electricity Transmission plc (NGET), a subsidiary of National Grid plc, 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. NGET is also the owner of the high voltage electricity transmission network in England and Wales.[3]

1.2. National Grid Gas plc (NGG), another subsidiary of National Grid plc, is the SO for the gas National Transmission System (NTS) in GB and has responsibility for the residual balancing activity on the NTS. The transmission and transportation licences of both NGET and NGG respectively require each to act in an efficient, economic and co-ordinated manner in performing their respective SO roles.

1.3. Generally each year, we develop SO incentive schemes that are designed to encourage NGET and NGG to respectively operate the electricity and gas transmission systems in an efficient and economic manner, and to effectively manage the costs of operating each system. These SO costs are borne by system users and, ultimately, by electricity and gas consumers.

1.4. The SO incentive schemes establish cost and/or performance targets that NGET and NGG are expected to achieve in performing their SO roles. If actual costs are below or performance is above the relevant target, NGET and NGG are permitted to receive an incentive payment, and similarly if actual costs exceed or performance is worse than the target, each faces an incentive penalty.

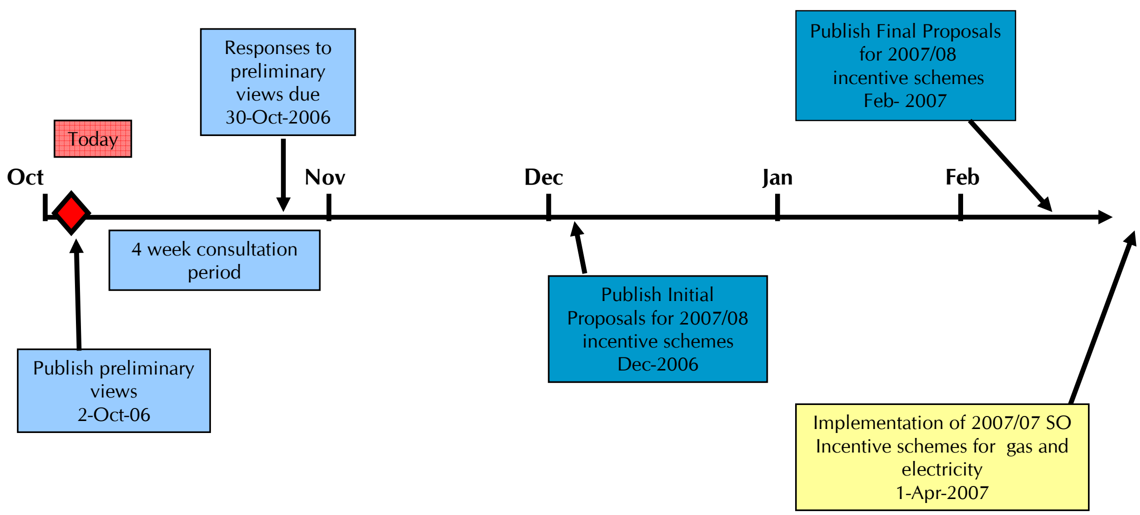
[3]. In Scotland, the transmission network is owned by Scottish and Southern Energy and by Scottish Power.

## Process

1.5. We published a letter on 5 July 2006 (the July letter) inviting interested parties' views on the historical performance of NGET and NGG as the respective electricity and gas SOs, and on the scope and form of the electricity and gas SO incentive schemes to apply from 1 April 2007.[4] At the same time, we also requested NGET and NGG to provide forecasts to us of expected SO costs and likely performance targets for operating the electricity and gas transmission systems from 1 April 2007. These are provided in Appendices 3, 4 and 5.

1.6. We have now reviewed NGET and NGG's forecasts, and have decided this year to separately consult on these before developing our initial proposals for the electricity and gas SO incentive schemes in December 2006. We believe that this will give third parties more opportunity to input into the process of setting the SO incentive schemes. Our timeline is shown in Figure 1.1. below.

**Figure 1.1: Timeline for SO incentive process**




1.7. In consulting on our preliminary views on NGET and NGG forecasts of SO costs from 1 April 2007, we are providing four weeks for interested parties to provide their feedback to us. Note there will be two further opportunities to comment on these, and any subsequent revised forecasts, during consultation on our initial and our final proposals in December 2006 and February 2007 respectively.

4 Refer to Ofgem's letter National Grid Electricity Transmission and National Grid Gas System operator Incentives 2007-08 - Invitation to Submit Views (Reference 112/06). Responses to the letter are summarised in Appendix 2.

## Structure and approach

1.8. This preliminary views consultation paper consists of five chapters. Chapter 1 provides a short overview of the SO roles for electricity and gas transmission networks, and outlines the process we intend to follow in developing SO incentive schemes for NGET and NGG for 2007/08, the structure of the document and the way forward.

1.9. Chapter 2 outlines the general role of the SO for electricity and gas networks, NGET and NGG's key SO cost items, and describes the past incentives schemes (internal and external), and NGET and NGG's performance relative to these schemes.

1.10. Chapter 3 outlines NGET's forecasts of external and internal SO costs for 2007/08. We also outline our preliminary views on the duration and scope of the external and internal incentive schemes, on NGET's forecasts, and provide our own preliminary forecasts of the pension and tax components of internal SO costs.

1.11. Similar to the previous chapter, Chapter 4 outlines NGG's forecasts of external and internal SO volumes and costs for 2007/08. We provide preliminary forecasts that we have developed for the pension and tax components of internal SO costs, and outline our preliminary views on the duration and scope of the external and internal incentive schemes, and on NGG's forecasts.

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

## Way Forward

1.13. Throughout this document, we pose a series of questions with respect to the forecasts of 2007/08 SO costs provided to us by NGET and NGG on which we are particularly interested in gaining the views of interested parties. However, these questions should not be seen as exhaustive, and we are interested in respondents' views on any aspect of NGET and NGG's forecasts. In responding to this document please can you be clear whether your comments apply to the gas and/or electricity incentive schemes. .

1.14. Responses should be sent to wholesale.markets@ofgem.gov.uk, to be received no later than **30 October 2006**. Further details of how to respond can be found in Appendix 1.

1.15. We will consider respondents' views on NGET and NGG's respective forecasts of electricity and gas SO costs provided in this document, and any updates to such forecasts, in the development of our initial proposals for SO incentive schemes, which we expect to consult on during December 2006. We will then develop final proposals and a statutory licence drafting for consultation, with a view to agreeing an SO incentive scheme with NGET and NGG to apply from 1 April 2007.

# 2. Background

**Chapter Summary**

This chapter outlines the general role of the SO for electricity and gas networks, the key cost items incurred by NGET and NGG in their respective SO businesses, and discusses the incentives schemes that have applied to costs incurred by NGET and NGG in their respective roles in operating the electricity and gas transmission systems in GB.

**Question box**

There are no specific questions in this chapter.

## System operator roles

### Electricity

2.1. As SO for the GB transmission system, NGET is responsible for energy and system balancing.5 In energy balancing, NGET's acts as 'residual balancer' and buys and sells electricity to keep the system in balance in real time, while system balancing requires NGET to take actions to ensure that the system remains within safe technical and operating limits. Its system balancing role can be further split between constraint management and system management:

- **Constraint management**: NGET takes actions to resolve constraints on the transmission system. These occur when there is not enough transmission capacity to transmit electricity from where it is being generated to where it is being consumed and may arise even if the system is otherwise in energy balance.

- **System management**: NGET contracts for a range of other balancing, or 'ancillary', services. These are mainly system balancing services required to maintain system stability, such as reactive power and frequency response.

2.2. NGET has a variety of tools available to assist it in performing its SO role, including: buying or selling electricity in the Balancing Mechanism (BM); through other traded products; signing Balancing Services Contracts (BSC); and/or agreeing

[5] 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 encompasses England, Wales and Scotland.

actions with the SOs of other markets that are interconnected with the GB electricity transmission system (for example, through the French interconnector).

*Offshore Transmission*

2.3. NGET has also recently been appointed designate SO for UK offshore transmission networks by the Secretary of State. NGET has informed us that this will require it to incur incremental costs for developing and implementing additional commercial and operational arrangements. These are not included in our preliminary views on NGET's SO costs set out in this document. We may consider how and whether any efficient SO costs associated with offshore transmission should be remunerated when NGET's GB SO role is amended to include offshore transmission, which is likely to occur from 1 April 2008.

**Gas**

2.4. As SO for the main gas transmission system, NGG's role involves residual gas balancing, system balancing, information provision and capacity/constraint management:[6]

- **Residual gas balancing**: NGG acts as the 'residual balancer' of the gas system, taking balancing actions to address any aggregate imbalance between the volume of gas entered and taken off the NTS by shippers.
- **System balancing**: NGG also manages the system to ensure that gas can be transported to the points on the system where customers are using gas and to secure gas for use in circumstances such as a network emergency.
- **Information provision**: NGG provides operational information and demand forecast information.
- **Day-to-day capacity/constraint management:** NGG manages the buy back of entry capacity where it is unable to deliver capacity that it has previously sold and also the management of constraints and transmission support at NTS exit points.
- **Incremental capacity investment:** Over longer timescales, NGG is provided with incentive allowances for investing in incremental entry capacity in response to signals provided by long term entry capacity auctions.[7]

6 Since 1999, NGG has been subject to incentives that have encouraged it to reduce the costs associated with the day-to-day management of the NTS and capacity buy-back. After 1 April 2002, the scope of NGG's incentives extended to cover costs related to managing entry and exit capacity constraints on its network.

7 NGG's roles in relation to capacity/constraint management are not considered further in this document. These as these areas are being progressed separately as part of work transmission price control process, under which investment revenue drivers and investment buy back incentives are being developed. For

2.5. In undertaking its balancing roles, the principal tool used by NGG is its ability to buy and sell gas via the On-the-day Commodity Market (OCM). NGG also contracts for Operating Margins gas for its reserve requirements, and has the ability to forward contract for balancing services where it considers this to be efficient and economic.

### SO costs

2.6. In carrying out their respective SO roles, NGET and NGG incur:

- **External costs**: associated with buying and selling energy (electricity or gas) and procuring balancing services in accordance with the activities outlined above.

- **Internal costs**: associated with day-to-day activities of the SO, and may be of an operating or capital nature, e.g. staff costs, costs associated with the operation of control rooms, or overheads such as IT and property costs.

2.7. Costs incurred by NGET and NGG in their respective SO roles for the electricity and gas transmission systems are borne by transmission system users and, ultimately, by electricity and gas consumers. As each is the sole provider of these services and competitive pressures cannot assist in placing downward pressure on costs, the transmission licence of NGET and the transporter licence of NGG obligates each to act in an efficient, economic and co-ordinated manner.

2.8. To encourage NGET and NGG to operate the GB electricity and gas transmission systems in an efficient and economic manner, and to effectively manage the costs of operating the systems, we develop incentive schemes that apply to their SO businesses, which are discussed in the following section.

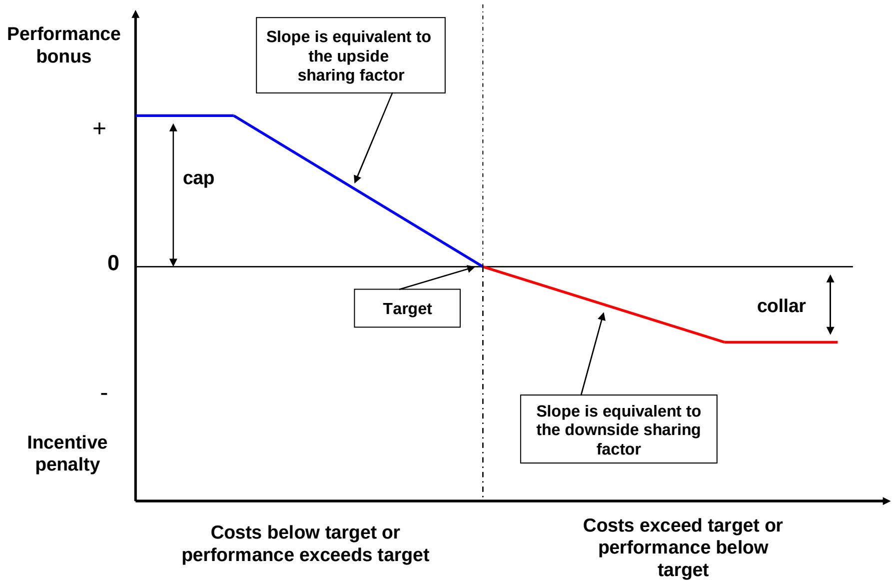
## System Operator incentive schemes

2.9. Under the SO incentive schemes that have been applied in GB, the SO is typically set one or more cost or performance targets to meet in carrying out its role.

2.10. As shown in Figure 2.1, if actual costs are below the target (or over-performance against the target), the SO is entitled to an incentive payment, set by **a sharing factor (the upside sharing factor).** If its costs are above the target (or under-performance against the target), the SO incurs an incentive penalty, set **by a sharing factor (the downside sharing factor)**. However, the SO's overall gains or losses are generally limited by applying a **cap** on incentive payments (profits) and a **floor (or collar)** on incentive penalties.

further information see Ofgem's Transmission Price Control Review: Updated Proposals (Reference 170/06).

**Figure 2.1: Representative SO incentive scheme**




2.11. In setting incentive scheme targets, sharing factors, and associated caps and floors, we aim to provide NGET and NGG with an appropriate balance of risk and reward that best serves the interests of transmission system users and, ultimately, electricity and gas customers.

2.12. For both NGET and NGG, we apply separate incentive schemes to their external and internal SO costs. Although incentive schemes for internal and external costs are very similar in structure, we do not typically apply a cap or a floor to internal SO costs due to the greater control that the SO has over these costs. However, to the extent possible, we aim to create incentive arrangements which ensure that the SO takes equal account of costs, regardless of whether they are internal or external.

2.13. In each case, the amount of the SO's costs that are recovered from network users depends on the SO's performance relative to the external incentive scheme targets. For internal SO costs, we set separate targets for operating (including pension and tax components) and capital expenditure, which give rise to a revenue cap, similar to the revenue cap that governs NGET and NGG's respective transmission and transportation operator businesses.[8]

8 See Ofgem's Transmission Price Control Review: Initial Proposals (Reference 104/06) http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/15595_104-06AMEND.pdf?wtfrom=/ofgem/whats-new/archive.jsp

2.14. The following sections describe the nature of SO incentive schemes that have applied to NGET and NGG as respective SOs of the electricity and gas transmission systems in recent years in more detail.

### Electricity SO incentive schemes

*External SO costs*

2.15. Beginning in 1996, we typically set annual incentive schemes to encourage NGET (and its predecessors) to undertake its SO role in the most efficient and economic manner possible.[9] Since 2001, NGET has been set an annual overall target for its controllable external SO costs, referred to as Incentivised Balancing Costs (IBC), i.e. both energy and system balancing costs are included in the same 'pot'.[10] Appendix 6 provides a more detailed overview of the components of IBC. Table 2.1 summarises the key parameters of the scheme in each year.

**Table 2.1: External SO incentive schemes[11]**

| £ m | Target | Sharing factors | | Cap | Floor | Actual | NGET share |
|---|---|---|---|---|---|---|---|
| | | Upside (%) | Downside (%) | | | | |
| **2001/02** | 382 | 40 | 12 | 46.3 | -15.4 | 263.0 | 46.3 |
| **2002/03** | 367 | 60 | 50 | 60 | -45 | 285.6 | 48.6 |
| **2003/04** | 340 | 50 | 50 | 40 | -40 | 280.8 | 32.2 |
| **2004/05** | 320 | 40 | 40 | 40 | -40 | 289.2 | 12.2 |
| **2005/06** | 378 | 40 | 20 | 40 | -20 | 427.2 | -4.0 |
| **2006/07** | na | na | na | na | na | na | - |

2.16. As shown in Table 2.1, for the four years from 2001/02 to 2004/05, the overall variation in balancing costs, net of transmission losses, was fairly stable in a range of £260 – £290 million, and NGET outperformed the relevant incentive target for each year.

2.17. Part of the increase in external SO costs in 2005/06 was anticipated, and reflects the widening of the scope of NGET's role as SO for the whole of GB following

9 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.

10 Adjustments are made to energy and balancing costs to account for increases/decreases in the volume of balancing activity NGET has to undertake (based on a term known as the net imbalance adjustment (NIA)). This reflects the fact that the overall volume of balancing activity is largely outside of NGET's control. The IBC term also incorporates transmission losses adjustment (TLA) terms, so that NGET has incentives to take into account the impact of balancing decisions on transmission losses.

11 Targets and actual IBC before 2005/06 have been recalculated net of transmission losses. Note that NGET share for 2005/06 reflects the expected impact of the Authority's recent determination of the amount of income adjustment that should be allowed with respect to notices of proposed IAEs submitted to us by NGET on 30 June 2006. For further information see Ofgem's decision letter (Reference 171/06).

the introduction of British Electricity Transmission and Trading Arrangements (BETTA) from 1 April 2005. However, despite the target reflecting the wider scope of NGET's SO activities, actual costs exceeded the target by almost £50 million.

2.18. On 30 June 2006, NGET submitted notices to the Authority of two proposed income adjusting events (IAEs) totalling £35.77 million for 2005/06.[12] We have considered the issues raised by NGET in its two notices, and have concluded that the events described in both notices constitute IAEs, and determined that a total income adjustment of £29.5 million should be allowed.[13] As a result, NGET will incur a penalty of around £4 million under the incentive scheme.[14]

2.19. For the 2006/07 year, Ofgem proposed two possible incentive scheme structures. NGET decided not to consent to licence modifications to implement either of these options. As a consequence, Ofgem is monitoring NGET's external costs under relevant licence and statutory obligations during the current 12 month period. This commenced on 1 April 2006 and will continue until 31 March 2007.

*Internal SO costs*

2.20. Due to the similarity in how targets are set for internal SO costs with the process for setting allowable transmission revenues, NGET's internal SO incentive scheme was originally set for a five year period to align with the transmission price control, which commenced on 1 April 2001 and ended on 31 March 2006. **NGET has consistently made a modest profit under its internal SO cost incentive scheme as shown in Table 2.2**.

12 Under its transmission licence, NGET is able to submit notices to Ofgem of proposed IAEs if costs (or savings) are incurred in connection with its SO activities that were not envisaged at the time that the IBC target was agreed. NGET's notices can be found at http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/15623_Ofgem_300606.pdf?wtfrom=/ofgem/whats-new/archive.jsp

13 See Ofgem's determination letter of 25 September 2006 (Reference 171/06).

14 The penalty is calculated as follows: Target IBC - (Actual IBC - income adjustment) X downside sharing factor (i.e. 378 - (427.2-29.5) X 20% ≈ 4)

**Table 2.2: Internal SO incentive schemes**

| £ m | Opex Target | Capex Target | Total Incentive Target | Sharing factors | | Opex Actual | Capex Recovery Actual | Total Recover y | NGET share |
|---|---|---|---|---|---|---|---|---|---|
| | | | | Up side (%) | Down side (%) | | | | |
| **2001/02** | 58.9 | 2.0 | 61.1 | 40 | 12 | 56.7 | 0.5 | 57.1 | 1.6 |
| **2002/03** | 53.2 | 5.6 | 58.8 | 60 | 50 | 49.4 | 3.2 | 52.6 | 3.8 |
| **2003/04** | 51.1 | 8.5 | 59.6 | 50 | 50 | 45.3 | 6.0 | 51.3 | 4.0 |
| **2004/05** | 48.2 | 10.1 | 58.3 | 40 | 40 | 43.5 | 8.2 | 51.7 | 2.3 |
| **2005/06** | 55.1[15] | 11.4 | 66.5 | 40 | 20 | 51.6 | 8.0 | 59.6 | 2.7 |

2.21. Ordinarily, we would have undertaken a review of internal SO costs ahead of the 31 March 2006 expiry date to establish appropriate allowances for 2006/07. However, we decided that it was preferable to roll the existing control forward for a single year to cover 2006/07 internal SO costs, and then set another long-term scheme from 1 April 2007.[16] This approach retains the alignment between the timing of this incentive and the setting of the main transmission price controls for NGET and NGG as respective owners of the electricity and gas transmission networks.

**Gas SO incentive schemes**

2.22. In its role as SO, NGG is subject to a number of performance and cost targets that govern its day-to-day management of the NTS. Brief details of the incentive schemes relevant to this consultation are included in the next sections.

*External SO costs*

2.23. For several years, NGG has carried out its day-to-day management of the NTS subject to the residual gas balancing and system balancing incentives discussed below.

2.24. NGG has operated under two **residual gas balancing incentives** (shown in Table 2.3):

- **Price incentive**: provides incentives for NGG to buy or sell gas for residual balancing reasons at prices as close to the market prices as possible (as measured by the system average price).

15 This target was adjusted after the publication of Final Proposals to allow for the implementation of BETTA
16 With the exception that the capital expenditure allowance for Transmission Services Schemes was transferred to NGET's transmission price control.

- **Linepack incentive**: provides incentives for NGG to minimise changes between opening and closing linepack each day on the NTS.

**Table 2.3: Incentive parameters for NGG's residual gas balancing incentives from 2001/02 to 2006/07 (money of the day)**

| | Price incentive parameters | Linepack incentive parameters |
|---|---|---|
| Performance measure target | 10% | 2.4mcm |
| Daily cap | £5,000 | £5,000 |
| Performance measure upper limit | 0% | 0mcm |
| Daily collar | -£30,000 | -£30,000 |
| Performance measure lower limit | 85% | 20.4mcm |
| Annual cap[17] | £3.5m | |
| Annual collar | -£3.5m | |

2.25. NGG's performance against the residual balancing incentives is summarised in Table 2.4.

**Table 2.4: Annual residual gas balancing incentive payments**

| £m | Price incentive payments | Linepack incentive payments | Combined incentive payments[18] |
|---|---|---|---|
| **2002/03** | 1.2 | -0.3 | 0.9 |
| **2003/04** | 1.3 | 0.1 | 1.5 |
| **2004/05** | 1.3 | 0.0 | 1.3 |
| **2005/06** | 0.8 | -0.1 | 0.7 |

2.26. NGG has also operated under two **system balancing incentives**, (shown in Tables 2.5 and 2.6 along with NGG's performance under these schemes):

- **Gas cost incentive**: provides incentives for NGG to manage the costs associated with shrinkage (i.e. energy used as compressor fuel, unaccounted for gas and unbilled energy).

- **System reserve incentive**: provides incentives for NGG to manage the cost of securing reserve at storage facilities (or import terminals).

[17] The annual cap and collar values apply to the price and linepack elements of the residual gas balancing incentives collectively.
[18] The combined residual gas balancing incentive payment is subject to an annual cap of £3.5m and an annual collar of -£3.5m, as outlined in Table 2.3.

**Table 2.5: Incentive parameters for NGG's gas cost incentive from 2001/02 to 2006/07 (money of the day)**

| £m | Target | Cap | Collar | Upside sharing factor | Downside sharing factor | Actual | NGG share |
|---|---|---|---|---|---|---|---|
| **2002/03** | 58.5 | 4 | -3 | 25% | 20% | 62.4 | -0.8 |
| **2003/04** | 61.9 | | | | | 44.4 | 4.0 |
| **2004/05** | 82.6 | | | | | 59.7 | 4.0 |
| **2005/06** | 112.7 | | | | | 91.1 | 4.0 |
| **2006/07** | 184.4 | | | | | - | - |

**Table 2.6: Incentive parameters for NGG's system reserve incentive from 2001/02 to 2006/07 (money of the day)**

| £m | Target | Cap | Collar | Upside sharing factor | Downside sharing factor | Actual | NGG share |
|---|---|---|---|---|---|---|---|
| **2002/03** | 16.8 | None | None | 100% | 100% | 15.9 | 0.9 |
| **2003/04** | 16.6 | | | | | 17.8 | -1.2 |
| **2004/05** | 16.6 | | | | | 16.3 | 0.3 |
| **2005/06** | 16.6 | | | | | 16.6 | 0.1 |
| **2006/07** | 16.6 | | | | | - | - |

2.27. From 1 October 2006, NGG will also be subject to the following quality of information incentives:

- **Demand forecast incentive**: this provides incentives for NGG to issue accurate demand forecast information to the market.
- **Website performance incentive**: this provides incentives for NGG in relation to the availability and timeliness of information provision on its website.

2.28. The structure of the demand forecast incentive for the period from 1 October 2006 to 31 March 2007 is shown in Table 2.7.

**Table 2.7: Incentive parameters for NGG's demand forecast incentive over winter 2006/07 (money of the day)**

| £m | Winter 2006/07 |
|---|---|
| -5% (Collar) | -1.6 |
| 0% (Benchmark) | 0 |
| 5% (Target) | 1.6 |
| 100% (Cap) | 9.2 |

2.29. The structure of the website performance incentive for the period from 1 October 2006 to 31 March 2007 is shown in Table 2.8.

**Table 2.8: Incentive parameters for NGG's website performance incentive over winter 2006/07 (money of the day)**

| £m | Winter 2006/07 |
|---|---|
| 0% (Benchmark) | 0 |
| 27% (Target) | 1 |
| 100% (Cap) | 1.5 |

2.30. Since 2002/03, NGG has outperformed its targets, earning incentive payments of around £16 million for the four years to 2005/06. NGG's incentive payments/receipts under the residual gas balancing incentives and the system balancing incentives are shown in Tables 2.4, 2.5 and 2.6 above. Further details in respect of NGG's performance under these SO incentive schemes are provided in Appendix B of our July letter.

*Internal SO costs*

2.31. We also set targets for NGG's internal SO costs. The current incentive scheme for these costs was set for 5 years and expires on 31 March 2007. As part of this scheme, NGG is rewarded by an upside sharing factor set at 40% of cost savings, and penalised by a downside sharing factor set at 35% of cost overruns. We did not set a cap or collar on these costs due to the perceived considerable certainty around these cost estimates. Table 2.9 provide a summary.

**Table 2.9: Internal SO incentive schemes**

| £ m | Opex Target | Capex Target | Total Incentive Target | Sharing factors | | Opex Actual | Capex Recovery Actual | NGG share |
|---|---|---|---|---|---|---|---|---|
| | | | | Up side (%) | Down side (%) | | | |
| **2002/03** | 23.5 | 9.8 | 33.3 | 40% | 35% | 31.0 | 4.4 | -3.34 |
| **2003/04** | 21.6 | 9.6 | 31.2 | 40% | 35% | 31.7 | 9.7 | -5.42 |
| **2004/05** | 20.8 | 10.2 | 31.0 | 40% | 35% | 34.9 | 14.8 | -8.27 |
| **2005/06** | 20.7 | 10.3 | 31.0 | 40% | 35% | 34.6 | 19.8 | -9.33 |
| **2006/07** | 19.9 | 8.6 | 28.5 | 40% | 35% | - | - | - |

2.32. During the present period 2002-07 NGG overspent its operational expenditure allowance by £10 million per annum on average, where the average annual allowance was £23 million. The total capital expenditure allowance for 2002 to 2007 was £42 million, where internal capital expenditure mainly consists of IT hardware and applications for two key projects - Ulysses and Gemini.[19]

[19] Ulysses was the replacement of the national control systems, management information system, telemetry outstations and the associated communications network. Gemini was the replacement of the commercial and regulatory systems such as AT Link RGTA systems.

## Summary

2.33. This chapter outlined the general role of the SO for electricity and gas networks, the key cost items incurred by NGET and NGG in their respective SO businesses, and discussed the incentives schemes that have applied to costs incurred by NGET and NGG in their respective roles in operating the electricity and gas transmission systems in GB.

2.34. The following chapter outlines forecasts provided to us by NGET on external and internal electricity SO costs for 2007/08, and our preliminary views on NGET's forecasts.

# 3. Electricity SO cost forecasts

**Chapter summary**

This chapter outlines the forecasts provided to us by NGET on electricity SO costs for 2007/08, our preliminary views on the duration and scope for electricity SO incentive schemes from 1 April 2007, and our preliminary views on NGET's forecasts.

**Question box**

**Question 1**: Do you consider that it is appropriate to have a form of indexation for external costs to wholesale electricity prices? If so, do you consider that the merits of this approach outweigh the additional complexity?

**Question 2**: If you consider that a form of indexation to wholesale electricity prices is appropriate, please give your views on the components of NGET's external costs that should be covered by indexation?

**Question 3**: Do you have any views on a possible approach of indexing through the use of a 'price risk band', which would adjust the IBC target only if wholesale electricity prices moved outside the price risk band, and any comments on the appropriate size of such price risk band?

**Question 4**: Do you have any comments on whether the current IAE licence provisions are appropriate, or whether they should be amended, and if so, how?

**Question 5**: Do you have any comments on NGET's overall forecast of, and assessment of drivers related to, external SO costs it expects to incur in 2007/08?

**Question 6**: Do you have any comments on NGET's forecast increases in Ancillary Services costs in 2007/08?

**Question 7**: Do you have any comments on our preliminary view that there are good prospects for external SO costs incurred by NGET in 2007/08 to be less than its initial forecast?

**Question 8**: Do you have any comments on whether there are any further potential rule amendments that might assist in placing further downward pressure on prices for Ancillary Services?

**Question 9**: Do you have any comments on how internal Scotland constraint costs might be best minimised during the 2007/08 external SO incentive scheme?

**Question 10**: Do you have any comments on whether the current IAE licence provisions are appropriate, or whether they should be amended, and if so, how?

**Question 11**: Do you have any comments on NGET's overall forecast of internal operating and capital SO costs it expects to incur between 2007/08 and 2011/12?

**Question 12**: Do you have any comments on our preliminary view that the efficient level of opex over the duration of the incentive scheme is £251.5 million?

**Question 13**: Do you have any comments on our preliminary view that the efficient level of capex over the duration of the incentive scheme is £47 million?

## External SO incentive scheme

3.1. This section sets out our preliminary views on the duration and scope for the external SO incentive scheme to commence from 1 April 2007, which have been developed taking into account the responses received to our July letter. We also provide an overview of NGET's initial forecasts of external electricity SO costs for 2007/08, and our preliminary views on these forecasts.

### Duration

3.2. Several respondents to our July letter suggested that, in the long run, a multi-year scheme may be more appropriate for external SO costs. In principle, we are supportive of setting the incentive scheme for a longer duration, including potentially aligning incentive schemes applying to external and internal SO costs with the five-year regulatory period for the transmission price controls. However, before doing so, we believe that a fundamental review of the external SO incentive scheme would be beneficial. We expect to undertake such a review during 2007.

3.3. Therefore, we believe it to be prudent to wait a further year before developing proposals for a multi-year incentive scheme given the short experience of operating under BETTA and current conditions in the wholesale markets. Therefore, **our preliminary view is that the next external electricity SO incentive scheme should be for 12 months (i.e. 1 April 2007 to 31 March 2008)**.

### Scope

3.4. As noted in the preceding chapter, under previous external SO incentive schemes we set a single target for the level of IBC. This target, through the calculation of Balancing Services Use of System (BSUoS) charges, determines the level of revenue that NGET recovers from network users.

3.5. In our July letter, we noted that there had been a significant increase in IBC during 2005/06 due to spikes in wholesale gas prices and constraint management costs, and we sought views on whether a 'bundled' incentive target was still appropriate, or whether there would be merit in separating constraint costs into a separate incentive. We also questioned whether elements of the target should be indexed to energy prices.

3.6. There were mixed views on retaining a single IBC target. Although some respondents suggested 'unbundling' the target would enhance the transparency of the scheme, most argued that retaining a single IBC target provided the strongest incentive to NGET to reduce overall balancing costs.

3.7. We recognise there are likely to be interactions between actions that might be taken by NGET for energy balancing, constraint and system management. For example, an action taken for constraint management purposes might also assist in achieving energy balancing objectives. For this reason **our preliminary view is that a single IBC target should be retained for the next external electricity SO incentive scheme**.

3.8. In terms of potentially indexing the (single) IBC target to energy prices, most respondents considered this warranted further investigation. NGET on the other hand argued expectations on energy prices should be reflected in the target, with indexation only being considered if this could not be achieved. In light of NGET's forecasts, and given the sensitivity of NGET's IBC forecasts to changes in wholesale electricity prices, we believe this continues to merit consideration, and revisit this issue later in this chapter.

### Form

3.9. At this stage, we are not consulting on the overall form of the incentive scheme to apply to external SO costs from 1 April 2007 - this will form part of our initial proposals consultation paper in December 2006.

3.10. However, as highlighted in Chapter 2, NGET's transmission licence provides for it to submit notices to us of proposed IAEs if costs (or savings) are incurred in connection with its SO activities that were not envisaged at the time the IBC target was agreed.[20] In considering NGET's IAE notices some respondents questioned whether the current IAE provisions are appropriate, and we would invite views on this from interested parties.[21]

### NGET's forecasts of 2007/08 external SO costs[22]

3.11. NGET notes that as we asked it to provide forecast of balancing costs earlier than in previous years, it has had less visibility of current year costs and a shorter time frame to produce its forecasts. Therefore, it has adopted a simplified forecast approach.

[20] For further information refer to Appendix 3 of Ofgem's Potential income adjusting events under NGET's 2005/06 system operator incentive scheme (Reference 135/06) http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/16029_135_06.pdf?wtfrom=/ofgem/whats-new/archive.jsp
[21] For further information refer to Ofgem's Decision Letter of 25 September 2006 (Reference 171/06) http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/16856_171_06.pdf?wtfrom=/ofgem/whats-new/archive.jsp
[22] The public version of the information provided to us by NGET is reproduced in Appendices 3 and 4.

3.12. To derive its initial forecasts, NGET extrapolated forward from 2005/06 IBC costs, after adjusting these downwards by £25 million to account for the impact of the Rough outage and the extreme cold weather in March 2006, which were out of the ordinary, and an anticipated future switch from the level of actual BM actions (and costs) in 2005/06 to increased utilisation of response and reserve services based on its experience of prices during 2005/06.

3.13. In its extrapolations forward from adjusted 2005/06 costs, NGET focused on four cost drivers which it anticipates will have the greatest impact on forecast IBC in 2007/08. These were: forward wholesale electricity prices; bid/offer multipliers (which link forward prices with forecast 'spot' prices in the BM); free headroom (i.e. the volume of part-loaded plant that is able to respond within BM timescales); and net imbalance volumes (NIV) (i.e. the amount by which the system is 'long' or 'short'). In addition to these four drivers, NGET's forecast of certain Ancillary Service costs was driven by specific cost drivers for these services. Details of NGET's analysis for each of the four main drivers are provided in Appendix 3.

3.14. NGET concludes that there are not likely to be any changes in free headroom and NIV between 2005/06 and 2007/08, and it also assumes that the bid/offer multipliers will remain unchanged from current levels. As a result, of the four main drivers, forward wholesale electricity prices are the main driver of NGET's IBC forecast. However, separately, some significant increases in Ancillary Services costs in 2007/08 are forecast by NGET to have at least as large an impact on its forecast of IBC.

3.15. NGET has forecast that total balancing costs in 2007/08 will reach £483 million, which compares with actual costs of £427.2 million in 2005/06 and its current estimate of £453 million in external SO costs for the current year to 31 March 2007. A summary of NGET’s forecast is provided in Table 3.1 below.[23]

**Table 3.1 External SO costs - 2005/06 to 2007/08 (£ million)**

| | **2005/06 (Actual)** | **2006/07 (Estimate)** | **2007/08 (Forecast)** |
|---|---|---|---|
| Balancing Mechanism | 168 | 140 | 140 |
| Balancing Services Contract Costs | | | |
| Ancillary Services | 240 | 296 | 325 |
| Trades | 47 | 47 | 47 |
| Constraints (a) | 82 | 72 | 72 |
| Transmission loss adjustment | -6 | 0 | 0 |
| Net imbalance adjustment (b) | 104 | 101 | 101 |
| **Total IBC** | **428** | **453** | **483** |

Notes

23 NGET notes that its forecast does not reflect the cost of implementation of CAP048 (Firm Access and Temporary Physical Disconnection) or CAP070 (Short Term Firm Access).

(a) In the short term, constraints may be managed through both the Balancing Mechanism and through contracts. Costs may therefore be incurred under both the Balancing Mechanism and Balancing Services Contract Cost categories, but are separately forecast by NGET. In the longer term, constraints may also be managed through Transmission System Services capital investment.
(b) Net imbalance adjustment is deducted, while the other values in Table 3.1 are summed to derive IBC.

3.16. NGET indicates that the change in costs from 2005/06 reflects:

- a decline in BM costs due to the removal of the one-off effect of Rough outage in March 2005 and the extreme cold weather in March 2006, and an anticipated future increased utilisation of response and reserve services based on its experience of prices during 2005/06, which is partially offset by an increase in costs resulting from higher forward wholesale electricity prices for summer 2007,
- increases in frequency response prices resulting in the forecast cost of mandatory and firm frequency response increasing by £30 million and £11 million respectively,
- the cost of standing reserve rising by £23 million (material supporting NGET's forecasts has been provided to us confidentially), and
- reactive power costs increasing by £9 million, as a result of higher summer power prices, to which reactive power prices are indexed.

3.17. NGET's forecast £10 million decline in constraint costs is predominantly the result of a reduction in Cheviot constraint costs (£8 million). While the impact of forecasts of within Scotland generation and demand levels in 2007/08 on the cost of managing this constraint are unclear, it appears at least some of the expected reduction in costs on the Cheviot boundary reflects an increase in summer capacity limits and the availability of inter-trip services on the interconnector.

3.18. A more detailed breakdown of NGET's forecasts for changes in individual Ancillary Services costs, which in aggregate are forecast to increase by £85 million in 2007/08 compared to 2005/06, is provided in Table 3.2 below.[24]

24 The 2005/06 year is used as a reference point for comparisons as there is still significant uncertainty around the level of costs that are likely to be incurred in 2006/07.

**Table 3.2: NGET forecast for Ancillary Services costs - 2005/06 to 2007/08 (£ million)**

| | 2005/06 (Actual) | 2006/07 (Estimate) | 2007/08 (Forecast) |
|---|---|---|---|
| **Reactive** | 54.7 | 61.0 | 64.0 |
| **Frequency response** | 65.4 | 90.0 | 106.0 |
| **Fast Reserve** | 36.6 | 37.0 | 39.0 |
| **Standing Reserve** | 42.2 | 55.0 | 65.0 |
| **Other Reserve** | 6.3 | 6.5 | 6.5 |
| **Warming** | 7.4 | 12.0 | 12.0 |
| **Black Start** | 14.5 | 17.5 | 18.5 |
| **SO-SO** | 11.9 | 12.0 | 12.0 |
| **Other** | 1.0 | 2.0 | 2.0 |
| **Total** | **240.0** | **293.0** | **325.0** |

*Ofgem's preliminary views*

3.19. To aid our own and third parties understanding of NGET's forecast, we asked it to provide us with information on the sensitivity of its IBC forecast to changes in its assumptions. Table 3.3 below summarises the key IBC drivers, their actual 2005/06 and estimated 2006/07 values, and the value used by NGET in its forecasts of 2007/08 IBC. The table also highlights our estimate of the impact on total IBC if the value of the driver used by NGET were to change by 10 percent. We also briefly comment on the assumptions made by NGET in relation to the cost of Ancillary Services.

**Table 3.3: IBC sensitivity analysis**

| Driver | Affected IBC component | 2005/06 (Actual) | 2006/07 (Estimate) | 2007/08 (Forecast) | Change in IBC of $\Delta$10% (a) |
|---|---|---|---|---|---|
| Summer electricity prices (£/MWh) | BM, NIA and TRAD | 32.19 | 36.70 | 44.00 | ±£4.6m |
| | Reactive | | | | ±£1.8m |
| Winter electricity prices (£/MWh) | BM, NIA and TRAD | 52.68 | 56.00 | 58.00 | ±£4.5m |
| | Reactive | | | | ±£2.9m |
| Bid multiplier | BM summer | 0.65 | - | 0.65 | ±(£10.64m) |
| | BM winter | 0.47 | - | 0.47 | (±£9.40m) |
| Offer multiplier | BM summer | 1.91 | - | 1.91 | ±£15.15m |
| | BM winter | 2.40 | - | 2.40 | ±£19.45m |
| Net imbalance volumes (average) | Net imbalance adjustment | -500MW | - | -500MW | ±£3.3m |
| Ancillary services prices (b) | Ancillary services | - | - | - | ±£16.4m |

Notes

(a) This column reflects the estimated impact of a 10 percent change in the assumed 2007/08 value of the driver listed in the first column. Where the figure in the last column is enclosed in brackets, it

indicates that the impact on total IBC is in the opposite direction of the change in the driver. For example, a 10 percent increase in winter bid net imbalance volumes reduces IBC by £9.4 million.
(b) This reflects the impact of a 10 percent change in prices for around 50 percent of Ancillary Services for which NGET has identified specific cost drivers.

Wholesale electricity prices

3.20. As indicated in Table 3.3, the average wholesale electricity price for summer 2005 (April to September 2005) was around £32/MWh, while the estimated average wholesale price for summer 2006 was just over £35/MWh (based upon data from 1 April to 25 September).[25] At the time NGET prepared its forecast, summer 2007 forward wholesale electricity prices were £44/MWh and winter 2007/08 at £58/MWh. Since the time that NGET prepared its forecast there have been reductions in the wholesale price forward curves for both gas and electricity. Summer 2007 is now trading at around £38/MWh and winter 2007/08 at £48/MWh.[26] Given these reductions in wholesale electricity prices, there is the scope for reductions to NGET's IBC forecast.

3.21. The recent movements in wholesale electricity prices resulted in us again questioning whether some form of indexation is appropriate. We do not think that it would be appropriate to completely remove any form of price risk from the SO, because it may manage this risk by taking actions such as contracting ahead.

3.22. However, we do want to give consideration to whether there should be a form of indexing, perhaps in the form of a 'price risk band' around wholesale electricity prices that would provide the appropriate incentives for NGET to manage risk, but would also be sufficiently flexible to adjust for structural changes in the wholesale markets that could not have been predicted at the time the incentive scheme was put in place.

3.23. For example, an incentive scheme could be set with a target based on the electricity price at the time the scheme was agreed, but with a 'price risk band' of say ±20%. If wholesale electricity prices moved outside the band, the IBC target could be adjusted accordingly.

3.24. We would like to invite respondents' views on whether indexation is appropriate given the sensitivity of IBC to wholesale electricity prices, and which elements, if any would be appropriate to index. Furthermore, if indexation took the form of a 'price risk band', we are interested in views about the appropriate size and symmetry of such a band. We would additionally welcome views from respondents on whether the complexity of such proposals might outweigh the potential benefits.

[25] Historical prices sourced from APX on 26 September 2006.
[26] Forward wholesale electricity prices were obtained from Heren on 26 September 2006.

Bid/offer multipliers

3.25. We note that IBC forecast is particularly sensitive to changes in bid/offer multipliers. NGET's forecast of bid/offer multipliers is based on the historical average relationship between forward prices and BM prices. We note that historical variability tends to be greater on the offer multiplier than the bid multiplier. We would welcome any views on whether NGET's forecast of bid/offer multipliers based on historical information is appropriate.

Net Imbalance Volumes (system length)

3.26. NGET's analysis also indicates that IBC is not particularly sensitive to changes in system length because the overall impact is moderated as movements in the Net Imbalance Adjustment term in the IBC calculation are largely offset by opposite movements in BM costs. We would welcome respondents' views on NGET's analysis particularly in light of changes that are being introduced into the electricity cash out arrangements through Modification Proposal 194 (P194).

3.27. P194 amends the Main Energy Imbalance Price so that instead of being calculated as a volume weighted average of all the eligible energy balancing actions, only the top 100 MW of energy balancing actions taken by the SO will contribute to the overall volume weighted average calculation. NGET's IBC forecast includes savings of £2 million resulting from this rule change.[27] We welcome views on whether this is an appropriate level of savings.[28]

Ancillary Services

3.28. In terms of Ancillary Services, while most respondents to our July letter were generally pessimistic about the prospects for reducing costs, there have been recent decisions and rule changes that lead us to believe there are opportunities for reductions in NGET's forecasts costs for these services. However, we would invite respondents to consider whether there are any further potential rule amendments that might assist in placing further downward pressure on prices for Ancillary Services.

3.29. NGET's forecast increase in the cost of Ancillary Services is primarily due to underlying increases in prices for frequency response, standing reserve and warming.

[27] NGET has provided confidential analysis that illustrates that our central view that balancing costs would be reduced by £13 million as a result of P194 equates to a reduction in IBC of approximately £3 million once the (counterbalancing) affect of the net imbalance adjustment term in IBC is taken into account.
28 We also note that parties have raised Modification Proposal 205, which increases the volume of energy balancing actions that contribute to the calculation of a volume weighted imbalance price to 500MW. We expect to make a decision on P205 during October 2006. For further information refer to http://www.elexon.co.uk/changeimplementation/ModificationProcess/ModificationDocumentation/modProposalView.aspx?propID=223

3.30. NGET's forecast for mandatory frequency response costs assumes that costs will rise by one percent per month. When we approved CUSC Amendment Proposal 047 (CAP047) (which allowed the market to determine Holding Payment prices for mandatory), we expected that response costs would initially rise, but then would stabilise.

3.31. As we noted in our decision letter on CAP107B[29], we believe that the reason that this has not yet occurred is due to the arrangements determining the Response Energy Payment (REP).[30] We consider that because, under the CAP047 arrangements, the REP is an administered price, providers have factored a risk premium into Holding Payment prices in order to compensate and limit their financial exposure. We believe that this will be addressed by CAP107B, which allows the REP to be more closely linked to market prices.

3.32. In approving CAP107B and allowing REP to more closely align with market energy prices, our expectation is that this should result in the true level of holding costs being revealed, enhancing market transparency and competition as a consequence, and ultimately benefiting customers.

3.33. With regards to the increases in standing reserve costs, we have reviewed the reasons underpinning NGET's forecast, but are not able to comment in detail on NGET's reasons, as to do so may be commercially detrimental to NGET in its reserve capacity tender process. However, we consider there are reasonable prospects that the actual level of standing reserve costs incurred by NGET in 2007/08 could be less than its initial forecast.

3.34. In terms of forecast warming costs for 2007/08, we believe that NGET has double counted £5 million of costs by including 'additional' costs in Ancillary Services, but not reducing BM costs which should fall commensurately under the new pricing arrangements.

Constraints

3.35. NGET forecasts Cheviot constraint costs to fall to around £22 million in 2007/08 (compared with £31.6 million in 2005/06), reflecting an increase in summer capacity limits and the availability of inter-trip services on the interconnector. However, the cost of managing constraints within Scotland is forecast to remain at £28 million in 2007/08, almost the same as the £28.5 million in costs incurred by NGET in 2005/06.

[29] In its decision letter published on 28 September 2006, the Authority directed implementation of CAP107B: Redefinition of Response Energy Payment for Mandatory Frequency Response - Alternative B, by 28 December 2006. This decision letter can be found at http://www.ofgem.gov.uk/ofgem/work/index.jsp?section=/areasofwork/elecgov/egov02

[30] The Response Energy Payment and the Holding Payment determine the total cost of utilising mandatory frequency response.

3.36. In our decision on NGET's IAEs, we allowed only £24.22 million in costs incurred by NGET in relation to internal Scotland constraints, £4.32 million lower than the actual costs incurred by NGET.[31] This was because we concluded that NGET's costs in 2005/06 were higher than those we would have expected to be incurred by an economic and efficient SO. We also found that NGET had not provided sufficient evidence that an active risk management strategy was in place to manage the cost of these constraints to the amount of the allowances included in the incentive scheme.

3.37. We note that despite NGET since having entered into a contract to manage a key internal Scotland constraint, costs have not fallen significantly. We would invite views on how internal Scotland constraint costs might be best minimised during the 2007/08 external SO incentive scheme.

3.38. In the preceding sections, we summarised NGET's initial forecasts of external electricity SO costs for 2007/08, and outlined our preliminary views on certain aspects of NGET's forecast. We now consider the form and scope of the internal gas SO incentive scheme, and NGET's forecasts of internal SO costs for 2007/08.

## Internal SO incentive scheme

3.39. It should be noted that the regulation of internal SO costs through the setting of allowed revenues based on approved operating and capital costs is very similar to the framework that applies with respect to network transmission assets. [32] For this reason, there has historically been a close alignment between the design of the internal SO incentive scheme and the transmission price control that applies to NGET as owner of the high voltage transmission network in England and Wales.

3.40. Our preliminary views on the duration, scope and form of the next internal SO incentive scheme are discussed below.[33] We also provide an overview of NGET's initial forecasts of internal electricity SO costs for 2007/08 to 20011/12, and our preliminary views on these forecasts.

### Duration

3.41. Consistent with the previous internal SO incentive scheme, it is proposed that the duration of the next scheme is aligned with that for the transmission operator transmission price control. Hence, **our preliminary view is that the incentive**

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[31] For further information refer to Ofgem's Decision Letter of 25 September 2006 (Reference 171/06) http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/16856_171_06.pdf?wtfrom=/ofgem/whats-new/archive.jsp

32 See Ofgem's Transmission Price Control Review: Updated Proposals, 25 September 2006 (Reference 170/06).

[33] Note that we have not previously sought views from interested parties on these issues, as our July letter focussed only on the performance of NGET, and the form and scope of the external SO incentive scheme.

**scheme for internal SO costs should be for five years, from 1 April 2007 to 31 March 2012**.

**Scope**

3.42. To further maintain consistency with the transmission price control, and previous internal SO incentive schemes, it is proposed that the current scope of the internal incentive scheme be retained. Hence, **our preliminary view is to retain the existing scope of the internal SO incentive scheme, with separate terms for operating expenditure (opex), capital expenditure (capex), pensions and tax**.

**Form**

3.43. At this stage, we are not consulting on the overall form of the incentive scheme to apply to internal SO costs from 1 April 2007 - this will form part of our initial proposals consultation paper in December 2006.

**NGET's forecasts of 2007/08 to 2011/12 internal SO costs**

3.44. Table 3.4 summarises NGET's forecasts of internal SO costs for the five-year period corresponding to the next transmission price control period. NGET forecasts opex over the period to total £251.5 million, and capex at £47 million.

**Table 3.4: NGET forecast SO internal costs - (£ million, 04/05 prices)**

| | 2007/08 | 2008/09 | 2009/10 | 2010/11 | 2011/12 |
|---|---|---|---|---|---|
| Opex | 51.1 | 49.6 | 49.9 | 50.4 | 50.5 |
| Capex | 12.0 | 9.3 | 9.3 | 8.6 | 7.7 |

3.45. NGET's operating expenditure consists largely of staffing costs, and its forecast opex profile reflects both staff reductions resulting from administrative efficiencies, and staff increases to deal with expected increase in wind and renewable generation capacity on the system.

3.46. NGET also expects its capital expenditure to drop from £12 million in 2007/8 to £9.3 million in 2008/9 million as spending on Integrated Energy Management System support and upgrades end in 2007/8. NGET forecasts also reflect a slight fall in facilities costs from 2007/8 to 2008/9, and increased expenditure in 2008/9 and 2009/10 on BM enhancements. NGET then expects capital expenditure to fall to £8.6 million in 2010/11 and £7.7 million in 2011/12 on the completion of these projects.

*Ofgem's preliminary views*

Operating costs

3.47. We have adjusted NGET's staff costs in line with its stated assumption on real wage growth, and insurance costs consistent with our initial proposals for the transmission price controls. Consequently, as shown in Table 3.5, **our preliminary view is that the efficient level of opex over the duration of the incentive scheme is £227.6 million**, which is £24 million below NGET's forecast.

**Table 3.5: Ofgem's preliminary view on NGET SO internal costs (£ million, 04/05 prices)**

| | 2007/08 | 2008/09 | 2009/10 | 2010/11 | 2011/12 |
|---|---|---|---|---|---|
| Opex | 46.3 | 45.6 | 44.6 | 45.7 | 45.5 |
| Capex | 11.1 | 7.5 | 8.3 | 7.4 | 6.7 |

Capital costs[34]

3.48. We propose that all the capital expenditure incurred (or forecast to be incurred) by NGET during the period 2001/02 to 2006/07 should be rolled forward in NGET's SO internal regulatory asset value (RAV) for 1 April 2007. We have also included capital expenditure associated with the introduction of One Hour Gate closure that was not included in the original allowance.

3.49. Overall NGET has under spent on its internal SO capex over the past six years and, to ensure consistent regulatory treatment, we have applied the specified sharing factors in rolling forward the RAV. We propose to continue using a seven year asset life to calculate regulatory depreciation. Further details will be provided in our initial proposals consultation in December 2006.

3.50. In terms of capital expenditure for the period 2007/08 to 2011/12, we have identified some minor inefficiencies in NGET's forecast capital expenditure relating to project management, system integration and the use of external contractors. As a result, **our preliminary view is that the efficient level of capex over the duration of the incentive scheme is £41 million**, which is £6 million below NGET's forecast.

3.51. We note that historical approved Transmission System Services (TSS) capital expenditure, which represents additional incremental investment that can be justified through a reduction in SO costs, has been rolled into the relevant transmission operator's regulatory asset value (RAV). Given the potential to further reduce SO

[34] In addition to the 'incentivised capex' discussed below, there remains a 'non incentivised' element from the split of NGET's RAV between SO and TO businesses in 2001. This element of capex is depreciated on a "straight line" basis and will be fully depreciated by 2010/11.

costs through investment in the transmission network, we would be interested in views on any specific investments in transmission infrastructure or equipment that might assist in reducing NGET's external SO costs.

Tax and pensions

3.52. To maintain consistency with our approach on the transmission price control, we intend to use a post tax cost of capital, which means that we need to establish a tax allowance for 2007-12. Our preliminary view on tax allowances is set out in Table 3.6 below. We have used NGET's tax calculations to set the allowances, and we have verified these calculations.

3.53. Again, to maintain consistency with our approach to the main transmission price controls, we have also calculated a separate allowance for NGET's pension costs, which is also set out in Table 3.6. The pension allowances have been calculated on the same basis as those for NGET's transmission price control.[35]

**Table 3.6 Ofgem's preliminary view on NGET SO tax and pension allowances (£m, 04/05 prices)**

| | 2007/08 | 2008/09 | 2009/10 | 2010/11 | 2011/12 |
|---|---|---|---|---|---|
| Pensions | 11.6 | 11.4 | 11.3 | 11.3 | 11.1 |
| Tax allowance (a) | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |

Note (a). The tax allowance is nil across the period as the capital allowances and tax relief NGET receives on capex and pensions deficit payments exceed the taxable profits.

## Summary

3.54. This chapter outlined the forecasts provided to us by NGET on electricity SO costs for 2007/08, and our preliminary views on the duration and scope for SO incentives schemes from 1 April 2007, as well as our preliminary views on NGET's forecasts.

3.55. The following chapter outlines the forecasts provided to us by NGG on elements of the gas SO incentive schemes for 2007/08, and our preliminary views on these forecasts and the incentive arrangements.

35 See Ofgem's Transmission Price Control Review: Updated Proposals, 25 September 2006 (Reference 170/06).

# 4. Gas SO cost and volume forecasts

**Chapter summary**

This chapter outlines NGG's forecasts of external and internal SO costs for the next incentive schemes. We also outline our preliminary views on the duration and scope of the external and internal incentive schemes, and on NGG's forecasts.

**Question box**

**Question 1**: Do you have any comments on whether the current IAE licence provisions are appropriate, or whether they should be amended, and if so, how?

**Question 2:** Do you have any comments on NGG's shrinkage volume forecast for 2007/08?

**Question 3:** Do you have any comments on our preliminary view on the appropriate shrinkage volume for 2007/08?

**Question 4:** Do you have any comment on which of the low, central and high case forecasts presented by NGG and in our preliminary views is the most appropriate basis for the system balancing gas cost incentive scheme target?

**Question 5:** Do you have any comment on NGG's gas reserve volume forecast for 2007/08?

**Question 6:** Do you have any comments on our preliminary view on the appropriate gas reserve volume for 2007/08?

**Question 7:** Do you have any comment on which of the low, central and high case forecasts presented by NGG and in our preliminary views is the most appropriate basis for the system balancing gas reserve incentive scheme target?

**Question 8**: Do you have any comments on whether the current IAE licence provisions are appropriate, or whether they should be amended, and if so, how?

**Question 9**: Do you have any comments on NGG's overall forecast of internal operating and capital SO costs it expects to incur between 2007/08 and 2011/12?

**Question 10**: Do you have any comments on our preliminary view that the efficient level of opex over the duration of the incentive scheme is £122.1 million?

**Question 11**: Do you have any comments on our preliminary view that the efficient level of capex over the duration of the incentive scheme is £41.5 million?

## External SO incentive scheme

4.1. This section sets out our preliminary views on the duration and scope for NGG's external SO incentive schemes to commence from 1 April 2007. We also provide an overview of NGG's initial forecasts for relevant elements of the incentive scheme and our preliminary views on these. Note that this section deals only with the residual gas balancing, system balancing and quality of information SO incentives. All other aspects of NGG's SO incentive arrangements are being taken forward as part of the transmission price control.

### Duration

4.2. In our July letter, we outlined a preference for the external SO incentive scheme to apply for a period of 12 months from 1 April 2007. Respondents expressed mixed views, with some preferring longer term arrangements to encourage cost management initiatives that may take more than one year to be realised. Others supported schemes with short durations that enable them to be revised more regularly to reflect prevailing market conditions.

4.3. In principle, we are supportive of setting the incentive schemes for a longer duration and aligning incentive schemes applying to external and internal SO costs with the five-year regulatory period for the transmission price control. However, before doing so, we believe that a fundamental review of NGG's external SO incentives would be beneficial. We expect to undertake such a review during 2007. Therefore, **our preliminary view remains that NGG's external SO incentives should be developed to apply for a period of 12 months from 1 April 2007**.

### Scope and form

4.4. Respondents to our July letter were generally supportive of the scope of NGG's existing external SO incentive arrangements. That said, several respondents questioned the need for the linepack incentive, and there was a mixed response to the appropriateness of the gas reserve incentive. While noting the specific issues highlighted by respondents on these aspects of the incentive arrangements, the overall view was that the current arrangements should form the framework for the 2007/08 incentive schemes.

4.5. In light of respondents' views, and in the context of our intention to conduct a fundamental review of the external SO incentives to apply to NGG from 1 April 2008 during which the issues raised by respondents can be considered, **our preliminary view is that the scope and related form of the external SO incentives should remain unchanged for the 2007/08 incentive period**. Therefore, the suggested scope and form of the incentive arrangements is set out in Table 4.1 below.

**Table 4.1: Suggested scope of NGG's external SO incentive arrangements**

| Role | Form | Scope |
|---|---|---|
| Residual gas balancing | Price incentive | The differential between the price of NGG's marginal eligible balancing actions (highest and lowest priced eligible balancing actions) relative to the system average price (SAP) |
| | Linepack incentive | The difference between opening and closing linepack each day on the NTS |
| System balancing | Gas cost (shrinkage) incentive | Costs associated with shrinkage (i.e. energy used as compressor fuel, unaccounted for gas and unbilled energy) |
| | System reserve incentive | Costs of gas held by NGG to provide gas system reserve |
| Quality of information | Demand forecast incentive | The SO's performance in terms of its demand forecasting |
| | Website performance incentive | The SO's performance in terms of the availability and timeliness of information provision on its website |

4.6. We will consult more fully on the overall level of the targets and the associated incentive parameters to apply to NGG from 1 April 2007 in our initial proposals consultation paper in December 2006. However, given the relative stability of these targets, at this stage we have put forward preliminary views on some incentive parameters for NGG's SO arrangements, which are discussed below. These may change based on views received in relation to the forecasts.

4.7. However, as with NGET's transmission licence, NGG's transporter licence provides for it to submit notices to us of proposed IAEs if costs (or savings) are incurred in connection with its SO activities that were not envisaged at the time its cost and performance targets were agreed. In considering NGET's IAE notices some respondents questioned whether the current IAE provisions were appropriate, and we would also invite views on this from interested parties with respect to gas SO costs.

*Residual gas balancing - price and linepack elements*

4.8. The general view expressed by respondents to our July letter was that the existing daily incentive structure, framed within overall annual cap/floor limits, has operated well to date and, as such, should be taken forward. However, one respondent questioned the effectiveness of the annual cap and floor applied to the residual balancing incentives, while another considered that the revenue neutral performance level within the price incentive should be revised upwards from its current level of 10 percent and that the downside should be steeper in order to sharpen the incentive scheme.

4.9. Having considered the responses received, **our preliminary view is for the form of both the price and linepack elements of the residual gas balancing incentive to remain unaltered for 2007/08** (as outlined in Table 2.3 in Chapter 2). This is in terms of both the overall sliding scale incentive format and the associated parameters (i.e. the performance target, caps and collars). As already discussed, we consider that the issues raised by respondents to the July letter are best considered as part of the more fundamental review of the incentive arrangements to apply from 1 April 2008 onwards.

*System balancing - gas cost (shrinkage) element*

4.10. The majority of respondents to the July letter supported the continuation of the system balancing incentive on gas costs. One respondent considered that it was important for an appropriate target to be set, given the revenue that NGG has earned from this incentive over recent years.

4.11. In light of the views received, **our preliminary view is that the existing sliding scale format for the gas cost incentive be retained, along with the majority of the existing incentive scheme parameters (i.e. cap, collar and sharing factors)**. However, note that the target value attached to the gas cost target volume should be revised on the basis of forecasts for 2007/08 in order to ensure that an appropriate target is set for the coming incentive period. This issue is discussed later in the chapter and the target value identified will influence the other incentive parameters meaning this preliminary view may be revised.

4.12. For the avoidance of doubt, our preliminary view is that the existing gas cost reference price methodology, used to derive the overall gas cost target, should be retained in its present form. Therefore, with the exception of the target value, our preliminary view is that the gas cost incentive scheme will remain as outlined in Table 2.4 in Chapter 2.

*System balancing - gas reserve element*

4.13. The majority of respondents to our July letter who commented on the system reserve incentive considered that it should be retained in its current form, although one respondent considered that the target value should be revised downwards to ensure that the scheme is effective.

4.14. Consequently, as with the gas cost element of the system balancing incentive, **our preliminary view is that the existing sliding scale format for the gas reserve incentive should be retained**. At this stage, we are only considering revising the target cost parameter whilst retaining the other existing parameters (i.e. sharing factors) unaltered. However, this view may change depending upon the target value identified for this incentive scheme.

*Quality of information - demand forecast and website performance elements*

4.15. At this stage our preliminary views concerning the form of the quality of information incentives for 2007/08 are as follows:

- **Maintain the sliding scale incentive scheme approach -** under this approach we would develop two-sided incentive scheme arrangements (noting that the winter 2006/07 website performance incentive has upside only). The winter 2006/07 incentives were designed to provide strong incentives for NGG to pursue 'quick wins' to improve performance ahead of and during winter 2006/07. As such, they provide an attractive reward package. Based on the expectation that these quick wins will have been achieved by the end of winter 2006/07, our preliminary view is that enduring, two-sided incentive arrangements should offer a more modest reward package to NGG as part of an appropriate risk/reward profile.

- **Introduce standard of performance obligations with penalties for under-performance -** under this approach, we would specify performance targets and penalties should NGG fail to meet these standards. The incentive structure here would be downside only.

4.16. Under either option, we will need to identify the appropriate performance benchmark upon which to base the incentive arrangements. At least two high-level options available are:

- **Maintain existing level of performance -** under this approach, the arrangements would provide commercial incentives for existing performance levels to be maintained.

- **Enhanced performance -** under this approach, the arrangements would provide commercial incentives for NGG to enhance performance levels relative to the current position.

4.17. Under both approaches, we will additionally need to consider which historic period of past performance to use in setting the benchmark. High-level options available include:

- **Winter 2006/07 performance -** this will be the latest period but we will have limited data available upon which to measure NGG's performance.

- **Winter 2005/06 performance -** a full data set is available for this period, but basing the benchmark on this period alone will not reflect any improvements in NGG's performance over the winter 2006/07 period.

4.18. We would welcome responses in relation to our preliminary views concerning the quality of information incentives.

### NGG forecasts for 2007/08

4.19. NGG was asked to provide forecasts in relation to the volume of shrinkage and its gas reserve requirements for 2007/08, in order to inform the development of the gas cost (shrinkage) and gas reserve incentives, which relate to NGG's system balancing role.[36] Forecasts of price are not discussed in respect of the shrinkage and gas reserve incentives. This is because prices for these incentives are specified via a gas cost reference price (which ensures that fluctuations in the wholesale gas price are reflected within the incentive scheme target) and via prices fixed in special condition C3 of the gas transporter licence in respect of the NTS respectively. Therefore, under the current arrangements, unlike for electricity SO costs, wholesale gas prices levels are not relevant in setting the targets for these incentives.

4.20. The main purpose of the following section is to provide an overview of NGG's initial volume forecasts for relevant elements of the SO incentive arrangements for 2007/08 and our preliminary views on these volume forecasts.

*Gas cost (shrinkage) volume*

4.21. NGG's assumptions and approach in developing its gas shrinkage volume forecast are outlined in Appendix 5. NGG has based its forecast for 2007/08 on historical analysis, including actual performance during 2005/06. As outlined in Table 4.2, for each component of shrinkage, NGG presents a low, central and high case.

**Table 4.2: NGG forecasts of shrinkage volumes for 2007/08**

| **(GWh)** | **2006/07 target volumes** | **2007/08 NGG forecasts** | | |
|---|---|---|---|---|
| **Category** | | **Low case** | **Central case** | **High case** |
| Own use gas | 7,425 | 6,096 | 6,472 | 7,066 |
| Unaccounted for gas | 1,661 | 1,022 | 1,114 | 1,788 |
| Unbilled energy | 75 | 152 | 152 | 719 |
| **TOTAL** | 9,161 | 7,282 | 7,750 | 9,585 |

- **Own use gas (OUG)**[37] - the main factor behind NGG's OUG forecasts is the continuing dominance of north-south flows, based on expected supply-demand patterns. There is an anticipated increase in OUG relative to previous years as a result of slightly higher interconnector and east coast flows.

- **Unaccounted for gas (UAG)**[38] - NGG's UAG forecasts have been derived on the basis of a six year average of observed UAG, corrected to take account of exceptional periods of negative UAG in 2003 and 2005/06.

[36] NGG was not asked to provide forecasts in relation to its residual gas balancing or its quality of information incentives. This is because the development of the residual gas balancing incentives does not rely on a forecast of gas price or linepack volume and, as yet, we have no operational experience of the quality of information incentives.
[37] Gas used for compression.
[38] Gas which remains after taking into account all measured inputs and outputs from the system, own use gas consumption, CV shrinkage and the daily change in NTS linepack.

- **Unbilled energy (CV shrinkage)**[39] - NGG's unbilled energy forecasts are based on anticipated supply-demand profiles. NGG assigns the forecast increase over the 2006/07 target to the impact of higher anticipated east coast flows on the level of CV shrinkage in both East Midlands and North East networks.

4.22. **Electric compression**[40] is a further element of the gas cost incentive. NGG has forecast that electric compression will be 12GWh in 2007/08., reflecting the current electric compression on the NTS at Lockerley and Peterstow.

Ofgem's preliminary views

4.23. In order to inform the development of an appropriate shrinkage volume target, we requested a shrinkage volume forecast from NGG, as outlined above. We also commissioned an independent review of NGG's forecast, in order to inform the development of an appropriate shrinkage volume target. This review was undertaken by TPA Solutions Ltd (TPA), and we consider it will assist us in establishing an appropriate starting point for the development of a gas cost target volume.[41] As such, **we have used TPA's forecast as the basis for our preliminary views**, which are shown in each of the Tables 4.3 to 4.6 and 4.9. More detail on TPA's analysis is provided in Appendix 7.

4.24. The comments and suggested revisions to NGG's forecast provided by TPA are summarised below:

- **OUG** - expected supply-demand patterns for 2007/08 suggest that gas compression requirements will be less than projected by NGG. The main factor behind this is reduced duty on compressors which assist north-south flows due to reduced flows through St Fergus (because of reduced flows from UKCS compared to previous years and the diversion of gas via the Langeled pipeline). This leads to the following OUG forecast, including assumed sensitivities around the central case:

[39] Energy which is unbilled due to CV capping under application of the Gas (calculation of Thermal Energy) Regulations 1996 and subsequently amended in 1997.
[40] Electricity usage associated with the operation of electric drive compressors on the NTS.
[41] TPA Solutions ltd is an independent consultancy providing commercial, technical and regulatory services to clients across the gas supply chain. TPA provided advice in relation to gas shrinkage and gas reserve issues as part of their technical support on the development of the transmission price control arrangements.

**Table 4.3: Forecasts of OUG volumes for 2007/08**

| (GWh) | NGG forecast | Preliminary view | Comment |
|---|---|---|---|
| Low case | 6,096 | 4,533 | 10% below the central case |
| Central case | 6,472 | 5,036 | Takes average of actual OUG in 2002/03 and 2003/04 (7196GWh) and reduces this by 30% |
| High case | 7,066 | 5,539 | 10% above the central case |

- **UAG** - NGG's current forecast of actual UAG for 2006/07 is 1,022GWh. Taking this projection and assuming that this can be maintained during 2007/08, we take 1,022GWh as the base for a revised central case for 2007/08. On this basis, a revised UAG forecast, including sensitivities around the central case, is as shown in Table 4.4.

**Table 4.4: Forecasts of UAG volumes for 2007/08**

| (GWh) | NGG forecast | Preliminary view | Comment |
|---|---|---|---|
| Low case | 1,022 | 820 | 20% below the central case |
| Central case | 1,114 | 1,022 | Takes average of forecast UAG for 2006/07 (1022GWh) as the central case |
| High case | 1,788 | 1,230 | 10% above the central case |

- **Unbilled energy** - the long term average trend of unbilled energy is much lower than NGG's projections for 2007/08 at around 75GWh. For the preliminary view forecasts, we have taken this historic performance as the low case and have taken NGG's central case as our own central case. On this basis, a revised forecast for unbilled energy is shown in Table 4.5.

**Table 4.5: Forecasts of unbilled energy volumes for 2007/08**

| (GWh) | NGG forecast | Preliminary view | Comment |
|---|---|---|---|
| Low case | 152 | 75 | Based on long term average unbilled energy allowance (of between 74GWh and 75 GWh from 2003/04 to 2006/07) |
| Central case | 152 | 152 | Based on NGG central case |
| High case | 719 | 210 | 20% above the central case |

- **Electric compression** - TPA expects that Peterstow will not run once gas flows at Milford Haven, leading to lower usage of electric compression. On this basis, a revised central case based on some use of Lockerley is shown in Table 4.6, with assumed upside and downside sensitivities.

**Table 4.6: Forecasts of electric compression volumes for 2007/08**

| (GWh) | NGG forecast | Preliminary view | Comment |
|---|---|---|---|
| Low case | 12 | 4 | 2GWh sensitivity below central case |
| Central case | 12 | 6 | Based on NGG central case, less Peterstow |
| High case | 12 | 8 | 2GWh sensitivity above central case |

4.25. An overall comparison between the NGG forecast and our preliminary view (informed by TPA's analysis) of shrinkage volumes for 2007/08 is presented in Table 4.7.

**Table 4.7: Forecasts of shrinkage volumes for 2007/08**

| (GWh) | Low case | Central case | High case |
|---|---|---|---|
| NGG forecast | 7,282 | 7,750 | 9,585 |
| Preliminary view | 5,432 | 6,216 | 6,987 |
| **Difference** | **-1,850** | **-1,534** | **-2,598** |

4.26. At this stage, and ahead of developing initial proposals in relation to the shrinkage volume target for 2007/08, we are keen to hear the views of market participants and interested parties in relation to both NGG's original shrinkage volume forecasts and those outlined in our preliminary views.

*Gas reserve volume*

4.27. Appendix 5 outlines the assumptions made and approach taken by NGG in developing its gas reserve volume forecast. NGG has based its forecast for 2007/08 on historical analysis, including actual performance during 2005/06. At a high level, NGG has presented a low case, a central case and a high case. On this basis, NGG's forecasts are outlined in Table 4.8.

**Table 4.8: NGG forecasts of gas reserve volumes for 2007/08**

| (GWh) | 2006/07 target | 2007/08 NGG forecasts | | |
|---|---|---|---|---|
| | | Low case | Central case | High case |
| **Volume** | 2,004 | 1,427 | 1,589 | 1,922 |

4.28. NGG's forecasts are based on different assumptions concerning gas supply and demand patterns during 2007/08. The supply-demand assumptions for each case can be summarised as follows:

- **Low case** - expected supply in this case is based on the winter 2006/07 base case supply forecast (as presented in the Winter 2006/07 Consultation document issued in May 2006[42]). Expected demand is derived from the 2006 forecast 1 in 50 severe demand curve adjusted to reflect the level of demand side response seen during 2005/06.

- **Central case** - expected supply in this case is the same as for the low case. Expected demand is again derived from the 2006 forecast 1 in 50 severe demand curve, but in this case there is no adjustment for recently observed levels of demand side response.

- **High case** - supply assumptions are the same as for the central case except that it includes a potential supply loss of 30mcm/d.

Ofgem's preliminary views

4.29. As for NGG's shrinkage forecasts, we sought an independent review of the forecasts from TPA, which we have used to inform our preliminary views. Again, more detail on TPA's analysis is provided in Appendix 7. The comments and suggested revisions to NGG's forecast provided by TPA, which form the basis of our preliminary views for consultation, are summarised below:

- **Double provision** - NGG's forecast may include double provision of reserve as a result of the overlap between different reserve requirements (i.e. duplication between reserves required for major events, for orderly rundown following gas supply emergency and to cover multiple event supply failures). We consider that provision for major events may be able to be eliminated as there is a very high probability that a major event would result in a gas supply emergency followed by orderly rundown.

- **Other reductions in Operating Margin (OM) requirements** - there are other factors that could further reduce NGG's OM requirements. First, the expected arrival of new import facilities and associated supplies could reduce the need for reserve to cover for supply failures. Second, the introduction of new electric compressors is expected to improve reliability, reducing reserve requirements associated with compressor trips. Third, on the assumption that higher gas prices have reduced 1 in 50 demand levels, there could be a corresponding reduction in reserve requirements.

4.30. As a result, **our preliminary views on gas reserve forecasts is shown in Table 4.9**. As with the shrinkage volume forecasts, at this stage we are looking for views from market participants and interested parties in relation to the projections presented.

42 'Winter 2006/07 Consultation Document', NG, May 2006. See http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/15058_8406b.pdf?wtfrom=/ofgem/whats-new/archive.jsp

**Table 4.9: Forecasts of gas reserve volumes for 2007/08**

| (GWh) | NGG forecast | Preliminary view | Comment |
|---|---|---|---|
| Low case | 1,427 | 1,137 | Based on preliminary view central case less further potential OM reductions (96GWh) |
| Central case | 1,589 | 1,233 | Based on NGG central case less double provision (356GWh) |
| High case | 1,922 | 1,589 | Based on NGG central case |

*Pricing system reserve*

4.31. In order to derive a cost target for the system reserve incentive, it is necessary to attach a price to the volume projections. At present, the prices specified for LNG storage services specified in special condition C3 of the gas transporter licence in respect of the NTS are used for this purpose. Consequently, this issue is closely related to the funding arrangements for the LNG facilities, which are being considered as part of the work on NGG's transmission price control. Ofgem's initial thoughts concerning the future regulatory treatment of the LNG facilities are set out in the updated proposals on the transmission price control.[43]

4.32. We intend to review the appropriate pricing arrangements for the system reserve incentive in our SO incentives initial proposals consultation document, to be published in December 2006, after parties have had an opportunity to respond to the regulatory treatment of the LNG assets being proposed under the TPCR.

## Internal SO incentive scheme

4.33. For the same reasons as for the electricity internal SO incentive scheme, there has historically been a close alignment between the design of the internal SO incentive scheme and the transmission price control that applies to NGG as owner of the NTS in GB.

4.34. Our preliminary views on the duration, scope and form of the next internal SO incentive scheme are discussed below. In this context, it is important to note that we have not previously sought views from interested parties on these issues, as our July letter focussed only on the performance of NGG, and the form and scope of the external SO incentive scheme.

[43] See Ofgem's Transmission Price Control Review: Updated Proposals (Reference 170/06).

## Duration

4.35. Consistent with the previous internal SO incentive scheme, it is proposed that the duration of the next scheme be aligned with that for the transmission price control. Hence, **our preliminary view is that the incentive scheme for internal SO costs should be for five years, from 1 April 2007 to 31 March 2012**.

## Scope

4.36. To further maintain consistency with the transmission price control, and the previous internal SO incentive scheme, it is proposed that the current scope of the internal incentive scheme be retained. Hence, **our preliminary view is to increase the existing scope of the internal SO incentive scheme, include tax and pensions costs in addition to operating expenditure (opex) and capital expenditure (capex)**.

4.37. We also consider that a separate term should be specified for xoserve charges. Values for this term to 2011/12 will be set as part of the Gas Distribution Price Control Review (GDPCR), further details of which will be set out in the GDPCR third consultation expected to be published in November 2006.

## Form

4.38. At this stage, we are not consulting on the overall form of the incentive scheme to apply to internal SO costs from 1 April 2007 - this will form part of our initial proposals consultation paper in December 2006.

## NGG's forecasts of 2007/08 internal SO costs

4.39. Despite a historical level of over spend of the order of 40 per cent, NGG forecasts its annual SO opex requirements from 2007/08 to 2011/12 to increase only marginally totalling £126.4 million, as summarised in Table 4.10 below. NGG's forecast capex between 2007/08 and 2011/12 is £64.4 million.[44]

**Table 4.10: NGG's forecast of internal SO costs for 2007/08 to 2011/12 (£ million, 04/05 prices)**

| | 2007/08 | 2008/09 | 2009/10 | 2010/11 | 2011/12 |
|---|---|---|---|---|---|
| Opex | 25.7 | 23.9 | 26.2 | 25.6 | 25.0 |
| Capex | 14.2 | 11.1 | 11.3 | 10.7 | 16.9 |

[44] Note that these values exclude NGG's forecast for NTS xoserve cost, with NGG expecting xoserve opex to be £5 million per year on average, and associated capex to be £15.2 million over five years. Xoserve capital costs are also part of the GDPCR consultation mentioned earlier.

*Ofgem's preliminary views*

Operating costs

4.40. The minor differences between our preliminary view on internal SO opex and NGG's forecast are primarily due to our identification of some further achievable efficiency savings and to normalisation adjustments required to remove restructuring costs.

**Table 4.11: Ofgem's preliminary view on NGG SO internal costs (£ million, 04/05 prices)**

| | 2007/08 | 2008/09 | 2009/10 | 2010/11 | 2011/12 |
|---|---|---|---|---|---|
| Opex | 24.3 | 23.3 | 25.4 | 24.7 | 24.4 |
| Capex | 12.8 | 8.3 | 5.5 | 5.3 | 9.6 |

4.41. However, and given NGG's historical level of opex, our preliminary view is that there is little scope for further reductions to NGG's forecasts (aside from a reduction of around 6 fulltime equivalent staff to eliminate some process overlaps between NGG's functions).

Capital costs

4.42. The overspend for all capital expenditure between 2001/02 and 2006/07 was £70 million, mainly in relation to the Ulysses and Gemini projects. Again, to ensure consistent regulatory treatment, we have applied the relevant 35% downside sharing factor to this overspend in rolling forward NGG's NTS SO internal RAV to 1 April 2007, which results in £24.5 million from the £70 million overspend being disallowanced. Further details will be set out in our initial proposals in December 2006.

4.43. NGG's proposed capex program for 2007/08 to 2011/12 was reviewed on our behalf by consultants TPA, and our preliminary view (based on this analysis) is that the allowed capex may be reduced by £22 million, reflecting:

- Identification of an alternative software package for dynamic network modelling and as a training simulator. This package is in use in comparable industries such as offshore gas and oil. NGG's forecast of the cost for this item is £14 million, compared to our estimate of £5 million.

- Delaying the replacement of the national control systems' hardware and software infrastructure components by one year. Such systems are presently only just being implemented under the Ulysses project, and hence the case for their replacement from 2010/11 is marginal. The effect of our adjustment is to remove £11.7 million of expenditure from 2011/12.

Tax and Pensions

4.44. Finally, to maintain consistency with our approach to the main transmission price controls, we have also calculated a separate allowance for NGG's pension costs, which is set out in Table 4.12. The pension allowances have been calculated on the same basis as those for NGG's transmission price control.[45]

4.45. To maintain consistency with our approach on the transmission price control, we intend to use a post tax cost of capital, which means that we need to establish a tax allowance for 2007-12. Our preliminary view on tax allowances is also set out in Table 4.12. We have set our allowances based on NGG's tax calculations.

**Table 4.12: Ofgem's preliminary view on NGG SO tax and pension allowances (£m, 04/05 prices)**

| | 2007/08 | 2008/09 | 2009/10 | 2010/11 | 2011/12 |
|---|---|---|---|---|---|
| Pensions | 6.3 | 6.4 | 6.4 | 6.7 | 6.9 |
| Tax allowance | 2.3 | 2.1 | 1.5 | 1.6 | 1.7 |

## Summary

4.46. This chapter outlined the forecasts provided to us by NGG on gas SO volumes and costs for 2007/08 (and later years for internal SO costs), and our preliminary views on the duration and scope for SO incentives schemes from 1 April 2007, as well as our preliminary views on NGG's forecasts. The following chapter briefly summarises our next steps.

[45] See Ofgem's Transmission Price Control Review: Updated Proposals, 25 September 2006 (Reference 170/06).

# 5. Way forward

**Chapter summary**

This chapter briefly summarises our next steps.

**Question box**

There are no specific questions in this chapter.

5.1. As previously discussed, we have decided this year to separately consult on forecasts of SO costs provided to us by NGET and NGG before developing our initial proposals for the electricity and gas SO incentive schemes. We believe that this will give third parties more opportunity to input into the process of setting the SO incentive schemes.

5.2. We will consider feedback we receive to this consultation, along with any updates of forecast SO costs provided to us by NGET and NGG, in developing our initial proposals setting out options for SO cost targets, upside and downside sharing factors and caps and collars. We will publish a consultation paper outlining our initial proposals and inviting feedback from interested parties in December 2006.

5.3. In light of responses to our initial proposals consultation, and any further forecast updates that NGET and NGG may provide, we will then produce our final proposals, impact assessment and statutory licence consultation in February 2007. This will ensure that the necessary licence modifications can be made for 1 April if NGET and NGG agree to accept one of our proposals.

5.4. Responses should be sent to wholesale.markets@ofgem.gov.uk, to be received no later than **30 October 2006**. Further details of how to respond can be found in Appendix 1. We would ask that respondents make it clear in their responses to which of the two sets of forecasts their comments apply. It would also assist us if you could **please provide arguments in support of your views.**

# Appendices

**Index**

# 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.

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 **30 October 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. It would be helpful if responses could be submitted both electronically and in writing. Respondents are asked to put any confidential material in the appendices to their responses.

1.6. Next steps: Having considered the responses to this preliminary views consultation, we intend to develop initial proposals for SO incentive schemes to apply to NGET and NG in 2007/08 that will then be consulted on in December 2006. 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 it is appropriate to have a form of indexation for external costs to wholesale electricity prices? If so, do you consider that the merits of this approach outweigh the additional complexity?

**Question 2**: If you consider that a form of indexation to wholesale electricity prices is appropriate, please give your views on the components of NGET's external costs that should be covered by indexation?

**Question 3**: Do you have any views on a possible approach of indexing through the use of a 'price risk band', which would adjust the IBC target only if wholesale electricity prices moved outside the price risk band, and any comments on the appropriate size of such price risk band?

**Question 4**: Do you have any comments on whether the current IAE licence provisions are appropriate, or whether they should be amended, and if so, how?

**Question 5**: Do you have any comments on NGET's overall forecast of, and assessment of drivers related to, external SO costs it expects to incur in 2007/08?

**Question 6**: Do you have any comments on NGET's forecast increases in Ancillary Services costs in 2007/08**?**

**Question 7**: Do you have any comments on our preliminary view that there are good prospects for external SO costs incurred by NGET in 2007/08 to be less than its initial forecast?

**Question 8**: Do you have any comments on whether there are any further potential rule amendments that might assist in placing further downward pressure on prices for Ancillary Services?

**Question 9**: Do you have any comments on how internal Scotland constraint costs might be best minimised during the 2007/08 external SO incentive scheme?

**Question 10**: Do you have any comments on whether the current IAE licence provisions are appropriate, or whether they should be amended, and if so, how?

**Question 11**: Do you have any comments on NGET's overall forecast of internal operating and capital SO costs it expects to incur between 2007/08 and 2011/12**?**

**Question 12**: Do you have any comments on our preliminary view that the efficient level of opex over the duration of the incentive scheme is £251.5 million?

**Question 13**: Do you have any comments on our preliminary view that the efficient level of capex over the duration of the incentive scheme is £47 million?

**CHAPTER: Four**

**Question 1**: Do you have any comments on whether the current IAE licence provisions are appropriate, or whether they should be amended, and if so, how?

**Question 2:** Do you have any comments on NGG's shrinkage volume forecast for 2007/08?

**Question 3:** Do you have any comments on our preliminary view on the appropriate shrinkage volume for 2007/08?

**Question 4:** Do you have any comment on which of the low, central and high case forecasts presented by NGG and in our preliminary views is the most appropriate basis for the system balancing gas cost incentive scheme target?

**Question 5:** Do you have any comment on NGG's gas reserve volume forecast for 2007/08?

**Question 6:** Do you have any comments on our preliminary view on the appropriate gas reserve volume for 2007/08?

**Question 7:** Do you have any comment on which of the low, central and high case forecasts presented by NGG and in our preliminary views is the most appropriate basis for the system balancing gas reserve incentive scheme target?

**Question 8**: Do you have any comments on whether the current IAE licence provisions are appropriate, or whether they should be amended, and if so, how?

**Question 9**: Do you have any comments on NGG's overall forecast of internal operating and capital SO costs it expects to incur between 2007/08 and 2011/12**?**

**Question 10**: Do you have any comments on our preliminary view that the efficient level of opex over the duration of the incentive scheme is £122.1 million?

**Question 11**: Do you have any comments on our preliminary view that the efficient level of capex over the duration of the incentive scheme is £41.5 million?

**CHAPTER: Five**

There are no specific questions in this chapter.

# Appendix 2 –July letter consultation responses

1.1. To assist us in developing initial proposals for the 2007/08 incentives schemes, we published on open letter on 5 July 2006 in which we invited views from interested parties on the performance of the SO businesses of NGET and NGG.

1.2. We received 12 responses to the open letter. The views of respondents on each of the questions posed by Ofgem in the open letter are outlined below. This section is intended to summarise the principle themes of the respondents' views only and is not intended to provide a comprehensive overview of the responses received.[46]

**Annex A questions: Electricity external balancing - SO incentive scheme**

*A1: Is the form and scope of the previous incentive schemes still appropriate?*

1.3. All but one of the respondents to Ofgem's open letter addressed this question. Of the 11 respondents, seven agreed that the form and scope of the previous incentive schemes was still appropriate, three parties did not agree it was appropriate and one respondent did not clarify their overall position.

1.4. The three respondents that did not support using the framework of previous schemes for 2007/08 considered that symmetrical sharing factors should be used in place of an asymmetrical risk/reward profile. One of these respondents argued that any incentive scheme should have a wide incentivised cost range and ex-ante definition of IAEs that excludes underestimation of general costs throughout the year. A further respondent noted that the scheme should be shallower and allow NGET the prospect of making a profit. The other party opposed to the ongoing use of the current framework considered that an incentive scheme is no longer required to incentivise NGET, but that if one were to be developed it should be relatively narrow eg. +/- 10%.

1.5. Seven of the 11 respondents supported using the form and scope of previous incentive schemes as a basis for developing a scheme for 2007/08. Two of these respondents considered that the sharing factors should be shallower than in past schemes. A number of respondents also noted that Ofgem should be rigorous in scrutinising the true value of balancing costs and set a target accordingly, and that the sharing factors should strike the right balance between risk and reward.

[46] Respondents views can be found on the Ofgem website http://www.ofgem.gov.uk/ofgem/search-result.jsp?plusorminus=plus&articleid=14558&keywords=system%20operator%20&page=1

1.6. The one respondent who was neither specifically in support of, nor opposed to, the use of the previous incentive scheme framework noted that while these schemes can be effective, there needs to be sufficient testing undertaken prior to implementation, and that caution should be exercised to ensure NGET is not overly rewarded.

*A2: Are there ways in which the process of setting incentive scheme proposals could be improved?*

1.7. Eight respondents addressed this question and made suggestions as to how the process of setting incentive scheme proposals could be improved.

1.8. Four of these respondents supported Ofgem commencing the incentive scheme process earlier in the year than has been the case previously, to properly consider NGET's forecasts and to ensure there is sufficient time to agree an incentive scheme with NGET. Several of the respondents noted that this is important to avoid ending up in a position similar to this year where no incentive scheme was able to be agreed, as monitoring is not an effective way of incentivising NGET. With respect to the monitoring arrangements in place this year, one respondent suggested there should be routine reporting on NGET's performance against IBC throughout the 2006/07 year.

1.9. One party considered that there should be a specific 'cut off date' in the consultation process, after which Ofgem should not consider any revised NGETs forecast if these can not be consulted on. This same party also suggested amending NGET's licence to ensure they will be subject to an incentive scheme. Another respondent suggested that some elements of the scheme are more volatile than others and that it may be preferable to fix these elements for longer periods. Finally, it was noted by one party that the 2 main areas for improvement in terms of scheme design are increasing the transparency of the BSIS forecasting process, and ensuring Ofgem offers NGET a range of incentive scheme options that are internally consistent (ie. high risk / high reward, and low risk / low reward).

*A3: Has there been a permanent change in the distribution of BM costs or is the apparent change in 2005/06 likely to have been due to one-off factors?*

1.10. Nine respondents addressed this question and put forward a wide range of views on whether or not there has been a permanent change in the distribution of BM costs. Four respondents felt that there probably has been a permanent increase in these costs, while two parties considered the change in costs in 2005/06 to be short term in nature. A further three parties put forward their views but did not offer a firm position on this question.

1.11. Of those respondents who considered there has been a real and permanent increase in BM costs, all felt this was at least partly due to increases in energy prices. Several parties also indicated that the introduction of BETTA and CAP047 had consequences for BM costs. This group of respondents considered these impacts to be permanent and therefore they should be taken into consideration when setting future incentive schemes. One of these respondents noted that the electricity market is entering a period of significant change which will have consequences for performing the SO role relative to the past 5 years.

1.12. Two of the respondents to this question considered that the factors driving the recent growth in BM costs are unlikely to persist in the long term. A further party noted that there is no change expected in 2007/08 which could have an impact on costs comparable to the impact of the introduction of BETTA.

1.13. Three parties recognised that factors such as high energy prices and Scottish constraint management costs have contributed to an increase in BM costs however these respondents didn’t offer a definitive view on whether these costs will be permanent or short term.

*A4: Is a bundled incentive scheme still appropriate, or would there be merit in separating constraint costs into a separate incentive?*

1.14. Ten respondents addressed this question, with four of these parties supporting the separation of constraint costs into a separate incentive. The remaining six respondents considered that a bundled incentive scheme is more appropriate.

1.15. Those parties that preferred an unbundled scheme felt there would be enhanced transparency if constraint management costs were considered as a separate component.

1.16. Two of the parties in favour of a bundled scheme considered that it would be impractical to have a separate incentive given system constraint costs cannot be accurately identified and measured. One of these respondents went on to add that the IAE recently raised by NGET with respect to constraint management costs has highlighted this. Several respondents noted that that there are economic benefits with a bundled scheme as it offers NGET the strongest incentive to reduce overall balancing costs.

*A5: What prospects are there for reducing Ancillary Services costs?*

1.17. Eight respondents addressed this question, with five parties considering there are not particularly good prospects for reducing Ancillary Services costs, and a further three providing general comments.

1.18. Three respondents felt that the scope to reduce these costs is limited because of the ongoing rise in energy prices. One of these parties noted that CAP107 will enhance market arrangements, and therefore efficient pricing for frequency response while another respondent considered that if CAP107 were to be implemented it would increase frequency response costs further. While not specifically assessing the prospects for reducing Ancillary Services costs, one respondent did suggest that the NGET’s reserve review may provide opportunities for cost reductions.

*A6: Has there been any underlying trends in NGET's procurement of Ancillary Services that merit consideration?*

1.19. Five respondents commented on trends in NGET's procurement of Ancillary Services. One of these respondents considered that CAP047 is allowing the true costs of providing frequency response to be realised and another party encouraged further, similar moves towards market based arrangements. One respondent noted that it was difficult to comment on this due to a lack of available information, while a further respondent to this question suggested there may be good reasons to further explore areas such as the use of ancillary contracts, and the increasing tendency towards locational purchases.

*A7: Is a transmission losses incentive appropriate?*

1.20. Nine respondents addressed this question, with seven parties considering that a transmission losses incentive is appropriate.

1.21. Those who supported a transmission losses incentive felt that NGET has sufficient control over transmission losses to justify an incentive being applied. One of these respondents noted that while a transmission losses incentive may be appropriate at present, if a zonal transmission losses scheme were to be introduced in the future, this may no longer be the case.

1.22. Two of the parties opposed to a transmission losses incentive considered that it is no longer appropriate and should not form part of the 2007/08 incentive scheme. One of these respondents considered that given it is not clear how the actions of NGET can influence these losses, it isn't appropriate for an incentive mechanism to be applied. The other party noted given the level of transmission losses has remained relatively stable over time and NGET has generally beaten its transmission losses volume target, the existing incentive may no longer be required.

*A8: Should a dynamic reference price be used?*

1.23. Those who supported the continuation of a transmission losses incentive also considered that a dynamic reference price should be used. No party expressed opposition to using a dynamic reference price.

1.24. Two of these respondents noted that the approach to setting an appropriate reference price should be detailed further in the September consultation, and a further party considered that sufficient assessment should be undertaken to quantify the value of including a dynamic reference price in terms of improving the incentive to manage transmission losses.

*A9: Does industry believe any price uncertainty should be reflected in the 2007/08 incentive scheme?*

1.25. Nine parties responded to this question, with seven agreeing that price uncertainty should be reflected in the 2007/08 scheme, or at the very least the possibility of doing so should be considered further by Ofgem.

1.26. A further two parties commented on this issue, with one stating that price uncertainty should continue to be addressed through the setting of caps and collars and the IAE provisions, and another noting that the impact of energy prices specifically should be reflected in the incentive mechanism.

*A10: Would price indexation be a desirable mechanism to manage these risks, if so can different options for price indexation be identified?*

1.27. Nine respondents indicated that they either supported price indexation as a means of capturing price uncertainty, or that this idea should be investigated further. Only one party explicitly opposed the concept of price indexation in the context of the 2007/08 scheme design.

1.28. The party opposed to the application of price indexation considered that it would reduce the incentive on the SO and isn't necessary. Instead, this party expressed a preference for the impact of energy prices to be incorporated into the setting of an incentive scheme cost target.

1.29. Among those parties in favour of considering or indeed applying price indexation for the 2007/08 incentive scheme it was noted that indexation should not be overly generous to NGET, nor should it introduce a high level of complexity and uncertainty for the rest of industry. Several parties noted that selecting an appropriate price indexation method may be difficult, and potentially encourage speculative behaviour by NGET to try and outperform the index.

1.30. Supporting parties expressed preference for any proposed indexation method to be fully consulted on, potentially including an Impact Assessment. Two of these parties went on to add that price indexation may remove the need for NGET to raise IAEs. A further respondent noted that the indexation factor would need to be 2-way, with target IBC reduced if wholesale prices fall over the incentive period, and that it could be beneficial to have a 'dead band' such that target costs would only be adjusted if wholesale markets varied above a specified level.

*A11: What is the potential impact on NGET's incentives and risks to customers?*

1.31. Five parties provided feedback on the potential impact on NGET's incentives of applying price indexation, and the potential risks for customers.

1.32. Four of these respondents felt that the impact of price indexation on consumers would be positive, given costs and risks to consumers could potentially be lower (and, as noted by one party, lower that in 2006/07 where customers are relatively exposed due to the absence of an SO incentive scheme). Another respondent noted that Ofgem should be able to tighten targets year on year as more experience in operating the scheme is built, and that this will have direct benefits for consumers. It was considered by one party that Ofgem should be cautious to ensure price indexation doesn't shift the risk of volatile prices on to market participants, and that it doesn't create perverse incentives for NGET.

**Annex B questions: Gas external balancing - SO incentive scheme**

*B1: Are the form and scope of the incentive schemes still appropriate?*

1.33. Seven respondents addressed this question, with all agreeing that the form and scope of the previous incentive schemes remains appropriate and that this framework should be used for the 2007/08 scheme.

1.34. One of these respondents supported the continued use of the existing framework but suggested that the relationship between the system and residual incentives be reviewed, and that the PPM should only apply on days when NGG take balancing actions. Another respondent noted that it is important for there to be a residual balancing incentive on NGG, and that more work is required to determine an appropriate reference price.

1.35. Another of the respondents to this question expressed support for continued use of the current incentive scheme framework, but noted that further consideration should be given to areas such as price indexation to reflect the potential uncertainty of prices and their impact on the incentive schemes.

*B2: Should future incentives continue to last for two years or should they be shorter or longer?*

1.36. There were six responses to this question, with parties fairly evenly split in terms of the preferred duration of the gas incentive scheme.

1.37. Two of the respondent indicated support for a longer scheme. One of these parties suggested that the incentive period should coincide with the Price Control period, however it was recognised by this party that it would be difficult to set the scheme structure and all relevant parameters over a long period. The other party in support of a longer scheme noted that while a longer term incentive scheme is preferable in theory, for the next few years it may be more realistic to set incentives on a short term basis. This party also raised the issue of aligning the incentive scheme period with the Price Control period, but recognised that doing this would require more stable markets than we currently have.

1.38. Three of the respondents to the consultation were in favour of setting an incentive scheme of 2 years or less. One party explicitly indicated support for an annual scheme even beyond 2007/08. Another respondent indicated preference for an annual scheme, on the basis that this would offer the most responsive approach to system operator incentives, or failing that for the scheme to last no longer than 2 years. The other of these three respondents favoured a multi-year scheme to provide opportunities for investment to reduce the long-term costs of system management, but did not clarify for how many years the scheme should endure.

1.39. It was considered by one respondent that incentive schemes are, in theory, of greater benefit when they run for longer than one year, but recognised that for the period 2007/08 it is preferable to consider a scheme on 1 year duration only.

*B3: Are daily incentive payments, subject to annual cap and floor, still appropriate?*

1.40. Six parties responded to this question, and all agreed that daily incentive payments, subject to annual cap and floor, are still appropriate.

1.41. Respondents considered that this approach seems to have worked well in the past and should be taken forward. One respondent questioned the effectiveness of the cap and floor applied to the price incentive payment, and considered that this may be largely redundant. A further respondent noted that it is appropriate that these incentives are set on a daily basis to reflect the balancing period, and new incentives that are being proposed now eg. regarding information provision, should also be applied on a daily basis and capped.

*B4: Are both residual balancing incentive schemes still required?*

1.42. Of the eight parties that responded to this question, all agreed that the price performance incentive should be retained. With respect to the line pack incentive, four of the eight parties considered that the reasons for retaining this incentive were less clear, and that Ofgem should consider removing this incentive in the 2007/08 scheme. Four of the respondents supported retaining the two separate incentives.

1.43. One respondent suggested the price incentive should be amended so that the intersect of 10% is raised to 15-20%. This respondent considered that an intersect of 10% is too low and causes the SO to avoid taking action early in the day because the price is unattractive, which leads to a need to take much larger actions later in the day to reach residual balance. This party went on to argue that if this higher intersect were to be applied it would be necessary to adjust the gradient of the incentive to ensure the price incentive is sufficiently sharp.

1.44. Among those parties opposed to the continuation of the linepack incentive, it was noted that preserving linepack is in the interests of the SO for operational reasons and therefore does not require an incentive. One of these respondents considered that it is questionable whether NG are able to materially influence the linepack position at the end of the day. Another party suggested that it may be useful to understand NGET’s likely behaviour in the absence of this mechanism before assessing whether it should be continued.

*B5: Are both system balancing incentive schemes still required?*

1.45. Four parties responded to this question, with all agreeing that a gas cost incentive is still required. With respect to the system reserve incentive, two respondents agreed this should be retained in some form while the other two respondents considered that it was difficult to reach a definitive view on the value of this incentive, but that there may be scope for changing this incentive.

1.46. Three of the respondents considered that given NGG has annually received the maximum £4 million payment with respect to the gas cost incentive, a more realistic target may need to be set that is not so easily achievable.

1.47. Respondents views on the system reserve incentive were more mixed. One party noted that any changes to the regime that affect how NGG procures its system gas will mean the system reserve incentive will need to be changed. Another party commented that it is very difficult to determine how effective the system reserve incentive is at keeping NGG costs down, while one party considered that only a modest incentive should be retained.

*B6: Is NGG's 100% exposure under these incentives still appropriate?*

1.48. Of the six respondents who addressed this question, four supported the 100% sharing factors being retained. The remaining two respondents suggested these sharing factors should be revised downwards, but for different reasons.

1.49. Those parties in favour of retaining NGG's 100% exposure felt that this framework has worked well in the past and there is no reason why this should be changed. However one party considered that given the sizeable payments being routinely made to NGG under the gas cost incentive, the 100% upside sharing factor could be revised downwards to avoid the risk of over-payment. Another party was in favour of reducing the sharing factors below 100& to reduce NGG's exposure under the scheme.

# Appendix 3 – NGET's forecast of external SO costs

## National Grid's Forecast of Incentivised Balancing Costs for Great Britain in 2007/08[47]

### Introduction and Assumptions

This appendix presents our forecast of Incentivised Balancing Costs (IBC) for Great Britain in 2007/08.

This IBC forecast has been developed earlier in the year than is normally the case. As such, to aid clarity and also to meet tighter deadlines, National Grid has simplified its forecasting models from those used in previous years.

The forecast process starts with an examination of the main cost drivers. We then consider how these costs might change in the future – that is, we extrapolate future costs based on experience of past patterns of costs, and on known market changes ahead of 2007/08.

This appendix begins by explaining the forecast method, and then looks at the historic performance of the drivers of IBC and the possible range of values for these drivers for 2007/08, based on recent experience. The appendix then discusses each element of the forecast, before presenting the overall forecast of GB incentivised balancing costs for 2007/08.

We assume in our forecasts that:

- The general scope and form of the incentive scheme remains the same for 2007/08;
- The impact of BSC modifications or CUSC amendments, beyond those already approved by July 2006, is not considered
- There is no inclusion of costs resulting from the implementation of CAP048 (Firm Access and Temporary Physical Disconnection) or CAP070 (Short Term Firm Access).

### Construction of Forecast

The forecast is aimed at ascribing a value to the term IBC, which is defined in NGET's transmission licence as:

IBC = CSOBM – NIA[48] + BSCC + TLA[49]

[47] The content of this appendix reflects in its entirety material submitted to us by NGET.

Where:

- CSOBM represents total costs incurred in the Balancing Mechanism (BM), minus the cost of non-delivery;
- BSCC represents balancing services contract cost. It includes Ancillary Services and trading costs;
- NIA is the net imbalance adjustment;
- TLA is the transmission loss adjustment for a Net scheme, and is defined as (TL−TLT)×TLRP, the product of transmission losses volume (TL) minus the TL target (TLT) and the transmission loss reference price (TLRP);

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

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

Where

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

The forecasting approach used to estimate the above IBC components, except for Constraints, is an extrapolation method. Constraint costs are forecast through a combination of detailed network analysis, risk assessment and probabilistic modelling as described in the constraints section.

We have simplified our approach to forecast drivers for 2007/08 and focussed only on those drivers that are currently active. Therefore, in developing the forecast we have considered the following key drivers to have the greatest effect on overall balancing cost:

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

[48] NIA here is defined as NIV×NIRP, where NIV=-TQEI. Thus, this is the opposite sign convention from the licence definition, which is TQEI×NIRP.
[49] The Formal Licence definition includes the terms OM and RT, which are both forecast to be £0 for 2005/06 and 2006/07.

Amongst these four, we expect variations in NIV and Free Headroom to be smaller and therefore, on average, to have a less dynamic effect on costs.

In addition to these four, we have historically considered the following three drivers:

- Plant Margin:
- Flows across the Anglo – French Interconnector
- Flows from Scotland to England

The effects of Scotland to England and Anglo-French flows are considered separately within the constraint forecast and Transmission Losses forecast. Plant margin is not considered to be a major driver of costs for 2007/08, as sufficient plant margin is expected to be available.

The final significant driver of forecast cost is market pricing of certain Ancillary Services for the provision of Reserve and Frequency Response. To forecast costs in these areas, we have additionally considered recent trends and drivers for these services.

There are other cost drivers that influence GB IBC indirectly but are not explicitly included as one of the key cost drivers. For example, the effect of fuel prices feeds into IBC through their effect on forward electricity and submitted BM bid/offer prices. This behaviour is reflected within the drivers above.

Different drivers impact on balancing costs in different ways. For example, forward wholesale electricity prices reflect the underlying costs of generation, which also feed through into our balancing services costs, such as BM costs and also through ancillary prices such as Reactive, which is index-linked to wholesale prices. BM prices clearly affect our balancing costs but our forecast of BM prices more closely reflects our view of competitiveness in the balancing mechanism.

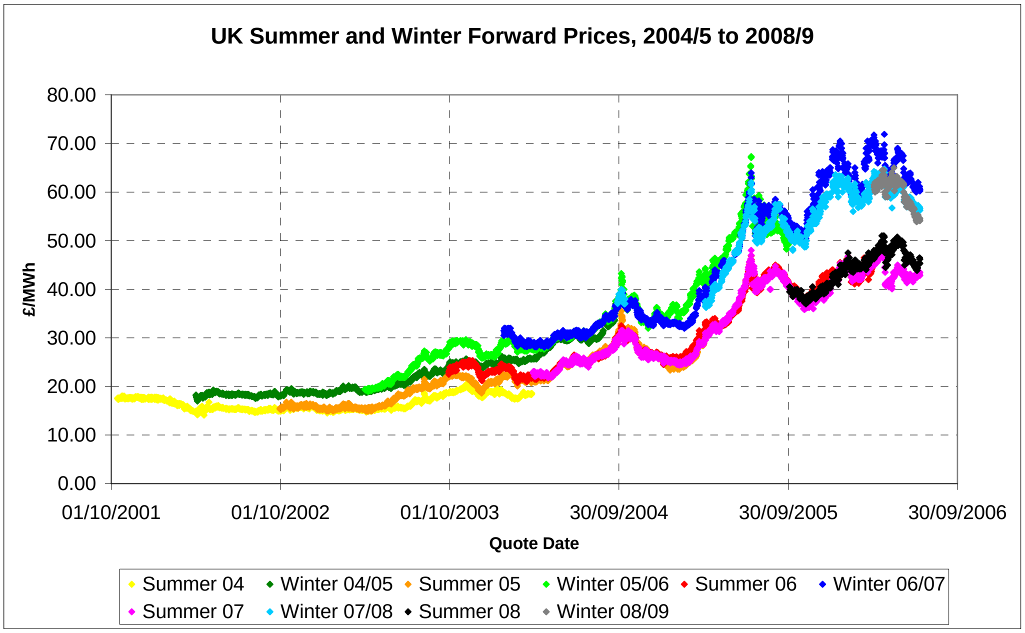
The historical and future performance of the above key cost drivers are described in the following section.

## Balancing Cost Drivers

### *Electricity Forward Price*

The electricity forward price impacts on IBC in several ways, including the costs of National Grid's pre-Gate trades and BM actions, and the volume and direction of flows across the Anglo-French interconnector. The latter, for example, has the potential to significantly impact on the costs of constraints.

Since March 2005 the forward price of electricity for summer 2007 and winter 2007/08 has increased markedly, in line with other forward prices. Summer baseload has remained in the range between £35/MWh and £50/MWh since July 2005 and has remained above £40/MWh since January 2006. The winter baseload forward price has remained almost entirely in the range of £50/MWh to £65/MWh since July 2005 and has remained above £55/MWh since January 2006.




The key factor behind these movements is the forward wholesale price for gas. The average baseload forward price for 2007/08 is £51/MWh[50] at time of writing.

*Balancing Mechanism Prices*

Prices in the Balancing Mechanism (BM) directly impact on the costs of balancing actions taken in the BM and (indirectly) pre-Gate.

The average accepted Bid and Offer prices accepted in the BM depend upon:

- the Bid and Offer prices submitted (which reflects the degree of competition in the BM as well as generators' behaviour); and
- the volume of actions taken by National Grid to balance the system.

The BM Bid market is competitive, with a large volume of bids accepted by National Grid principally for energy balancing. In contrast, the average accepted BM Offer price is more volatile from month to month. Our analysis suggests this is because the volume of offers taken is smaller than the volume of bids and, as a result, the average price of offers is more sensitive to prevailing market conditions that drive the actions taken by National Grid for margin and constraints.

The first graph below show the rise in Offer and Bid prices over 2005/06 driven by rises in generation costs, linked to wholesale gas price rises.

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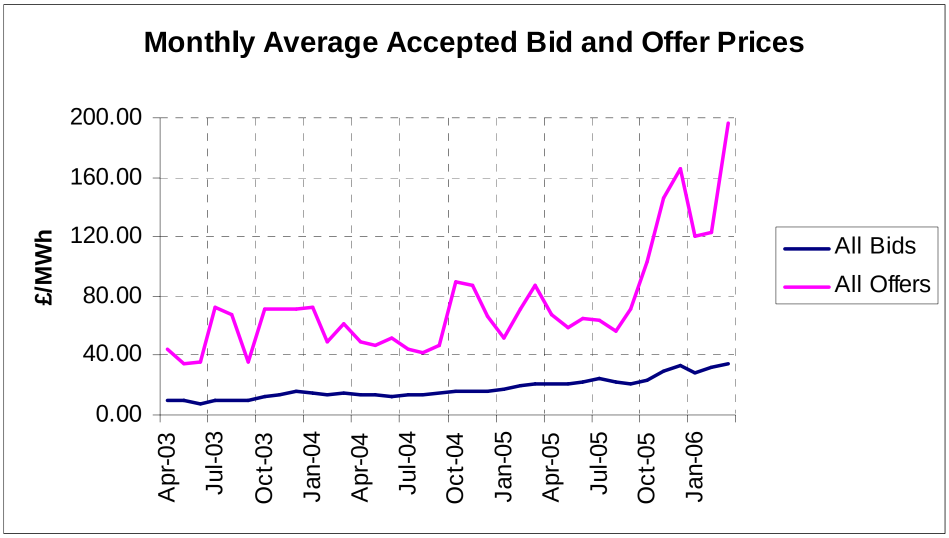
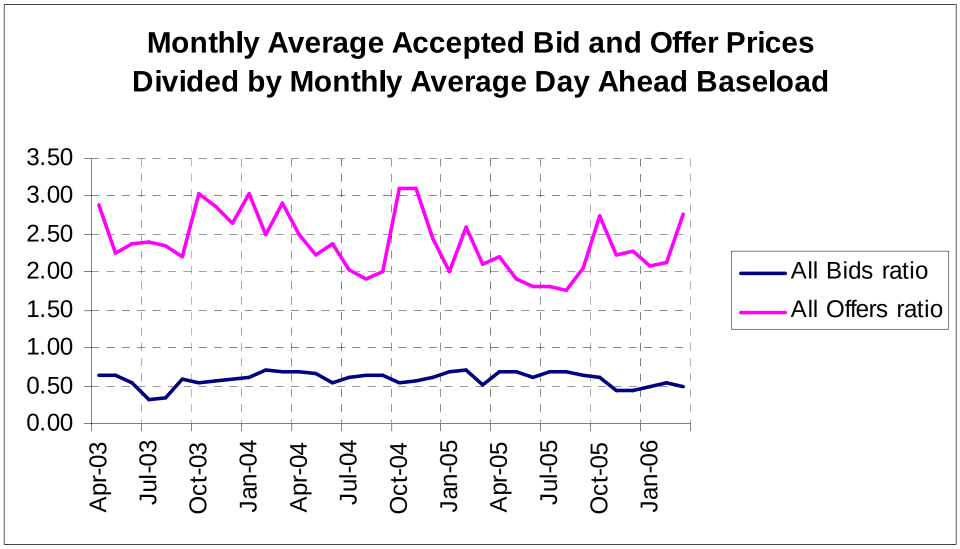
[50] Argus European Electricity Report, 17th July 2006.

The second graph below shows that, despite rises in prevailing prices, the relationship between BM Bid and Offer prices and forward wholesale electricity prices has been more stable:

The more competitive Bid market has a very stable relationship to wholesale, remaining close to, or a little above, 0.5. However, the larger volume of Bids taken means that even a small variation in this ratio (say from 0.5 to 0.6) can have a large impact on costs.

As discussed above, the ratio of Offer price to forward wholesale electricity price is more volatile, varying between approximately 1.7 and 3.1 over the past 3 years.



*Net Imbalance Volume (NIV)*

NIV is the measure of market length, or the net energy imbalance position of the market. It is calculated as the net volume of balancing actions taken by National Grid in the Balancing Mechanism and pre-Gate Closure.

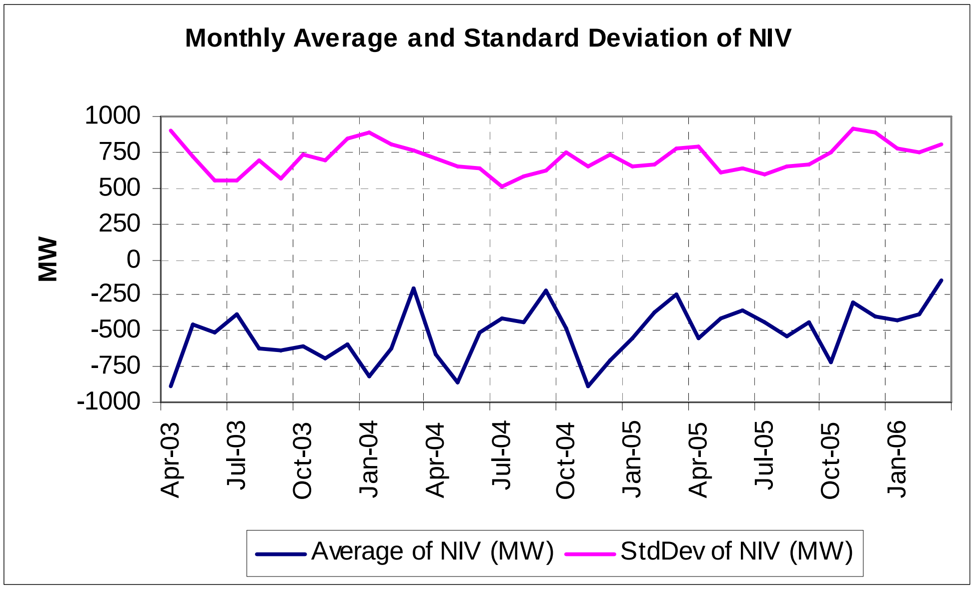
NIV directly determines the volume, and hence the costs, of Bids and Offers which National Grid has to take to balance the market. It also affects the amount of operating margin available to us from the market at Gate Closure.

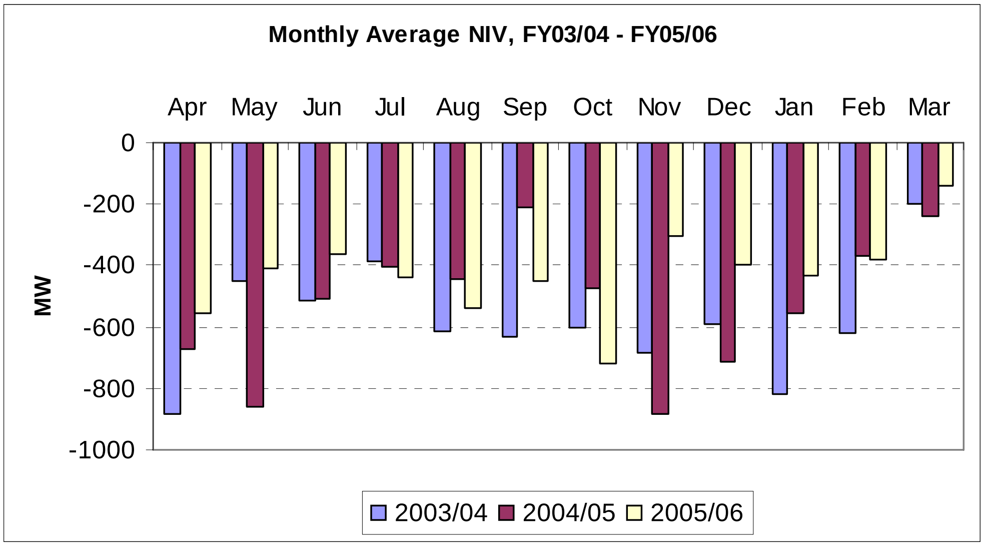
NIV depends upon a number of factors, but is mainly affected by the actions and policies of suppliers, for example their:

- demand forecasting accuracy,
- risk profile, and
- risk management strategy.

In the majority of Settlement Periods NIV - which approximately follows a Normal distribution - is negative, indicating a long market that National Grid must resolve by taking bids in the BM. This pattern reflects the asymmetric risks faced by suppliers associated with the current dual cash-out pricing arrangements.

It can be seen from the graphs below that average NIV became less negative over winter 2005/06, perhaps as a result of higher wholesale electricity prices. Over 2005/06, the standard deviation of NIV has remained in line with historic trends.



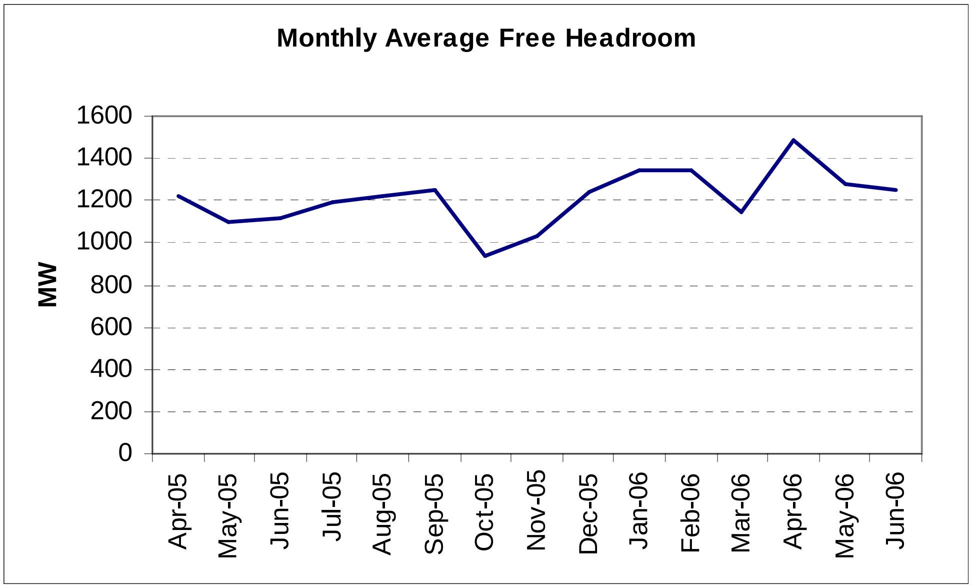



*Free Headroom*

At present we are still undertaking detailed analysis of the availability of Free Headroom during 2005/06 and will share our results once this completed. A number of new elements have made the calculation of historic free headroom more complex than in previous years, these include:

- Sterilisation of Free Headroom behind export constraints, including in Scotland
- Unavailability of apparent free headroom on plant such as Hydro and wind.

Therefore, for this forecast we have assumed that free headroom remains in line with levels seen in the recent past (I.e. 2004/05 and 2005/06). We also acknowledge that the introduction of P194 may alter market behaviour and hence affect the level of free headroom available in the BM. Analysis on the possible effects of P194 has been provided to Ofgem separately to this appendix.



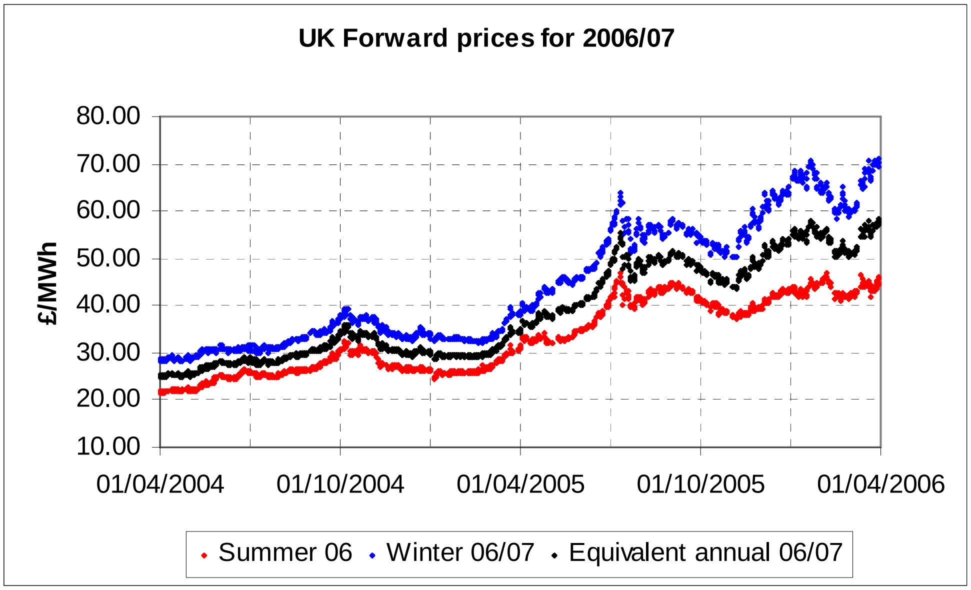

*Scenarios – forecast range of balancing costs drivers*

In order to calculate the range of possible balancing costs we have developed a likely upper and lower bound for each of the above drivers, based on recent historic experience. In addition to an upper and lower bound, we have identified the current value of that driver, based on current forward market prices or currently observed behaviours.

This allows us to develop a view of the possible range of forecast costs, based on the range of values for each of these drivers. It is likely that these values will change and with them our view of forecast costs is likely to change. However, we believe the upper and lower bounds, based on historic experience, represent a reasonable current view of the likely range of variation in the value of these drivers.

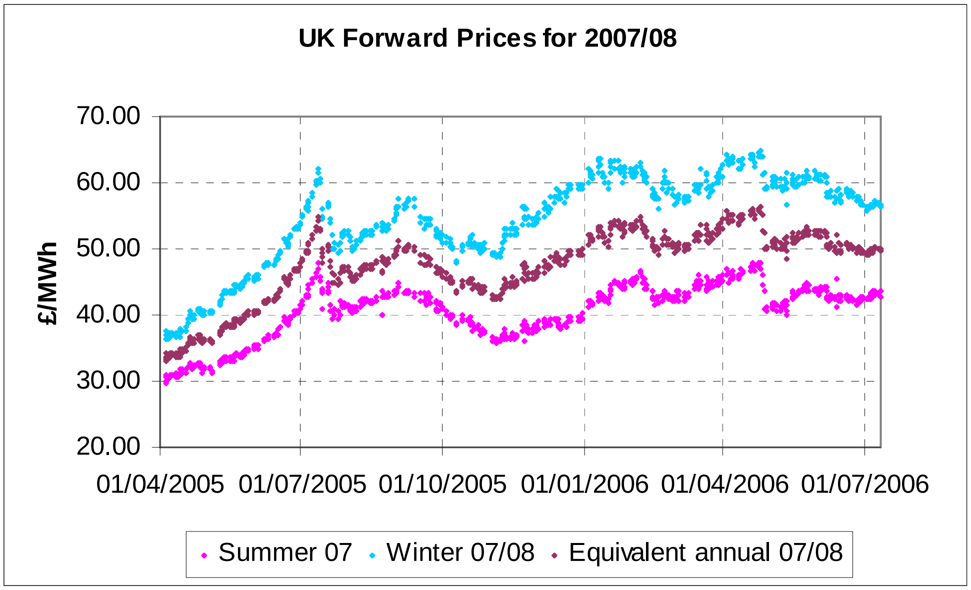
**Forward Price Assumptions**

Our current, and thus mid view, of power price is taken direct from the prices in the market (as of Monday 17/July/2006).




The upper case is set simply from the above chart as the maximum forward price for 2007/8, seen over the last 12 months. Likewise, the lower case is set as the minimum forward price seen.

| ***Case*** | ***Summer*** | ***Winter*** |
|---|---|---|
| ***Upper*** | ***£49/MWh*** | ***£ 66/MWh*** |
| ***Lower*** | ***£39/MWh*** | ***£ 50/MWh*** |
| ***Current*** | ***£44/MWh*** | ***£58/MWh*** |




Forward prices for 2006/07 have reached similar and even greater levels than those seen for 2007/08. We will continue to review our forecast assumptions for 2007/08 prices as these evolve through 2006.

**BM Price Forecast Assumptions**

We have forecast the likely range of BM prices based on the historically observed ratio of BM prices to wholesale prices discussed above. To calculate the possible range of annual average ratio we have used the maximum and minimum value of the rolling month average, as shown below. It is clear that the historic trend for Bid prices is around or a little above 0.5, varying between 0.6 and 0.5. For Offers the ratio sits in the range of 1.8 to 3.1.

For our forecast we have assumed there is no change in Bid/Offer ratios to the average of the 12 monthly values for 2005/06, namely 0.58 and 2.15. We have also identified the following as likely upper and lower bounds for these ratios, as the maximum variation seen of any 3-month rolling average about these annual averages.

| ***Case*** | ***Bids*** | ***Offers*** |
|---|---|---|
| ***Upper*** | ***0.54*** | ***2.30*** |
| ***Lower*** | ***0.62*** | ***2.00*** |
| ***Current*** | ***0.58*** | ***2.15*** |

For the forecast extrapolation, these values are split into the average summer and winter values. These are shown in the table below.

| ***Case*** | ***Bids*** | ***Offers*** |
|---|---|---|
| | ***summer : winter*** | ***summer : winter*** |
| ***Upper*** | ***0.62 : 0.44*** | ***2.01 : 2.50*** |
| ***Lower*** | ***0.68 : 0.50*** | ***1.81 : 2.30*** |
| ***Current*** | ***0.65 : 0.47*** | ***1.91 : 2.40*** |

Note that, because Bids are negative volume, the ‘upper’ value for Bids is the smaller value.

**Cost of Balancing Mechanism plus Trades**

*Methodology*

Our full model of the incentivised costs of the Balancing Mechanism plus Trades (‘IBMC+TRAD’) is a multi-scenario extrapolation, which includes modelling of how we meet the energy imbalance, and a derivation of our actions to meet reserve requirements (also known as operating margin) from first principles.

In the timescales of this forecast, we have not yet run this full model for 2007/8. Instead, we have extrapolated the outturn volumes and prices for CSOBM, NIA, and Trades for 2005/6, by simple multipliers that reflect our forecast year-on-year changes in BSIS drivers, as described above. Because we do not discern any strong pattern in the volume drivers of NIV and Free Headroom, the forecast BM+TRAD volumes are unchanged from the 2005/06 outturns. Analysis on the possible effects of P194 has been provided to Ofgem separately to this appendix. However, we do not believe that the imbalance price changes initiated by P194 will have a significant impact on our central forecast of BM costs and have therefore not factored any P194 effects into our forecast.

The forecast is built up from the 2005/06 outturn as follows:

1. We start with the 2005/06 outturn of £427.1m; this is broken down into our forecast categories: IBC = CSOBM – NIA + TRAD + AS + TLA.
2. We then adjust this outturn to allow meaningful comparisons going forward

- First, £72.1m of outturn Constraint costs are separated out from the above terms, because we forecast constraint costs separately.
- Then we adjust the basic 2005/06 figures to correct for events that we do not expect to be repeated under our base case scenario, but similar events remain as potential risks:

- The costs in one week of mid-March 2006, when the failure of Rough coincided with cold weather were extreme and unprecedented; although there is some possibility that such costs recur. Our analysis indicates that approximately £17m of excess costs can be attributed to this event. We have therefore removed £17m of cost and volume from our forecast basic data, because our central forecast does not embody such costs.
- We also acknowledge that additional firm Frequency Response and Reserve services would have been procured during 2005/06 given foresight of outturn winter prices. We estimate £18m could be saved from 2005/06 BM costs as a result of increased Firm procurement. The (lower) additional cost of Firm procurement that displaces the £18m of BM costs has been reflected within our Ancillary Services costs for Standing Reserve and Firm Response.

**3.** This 'adjusted' forecast basic data is then extrapolated forwards into year 2007/08 based on our price multipliers.

*Forecast*

The output of our forecasting model for 2007/08 based on the balancing cost drivers and "Current" assumptions discussed in the preceding sections is shown below.

| | Summer 2007 | | | Winter 2007/08 | | | Total 2007/8 | | |
|---|---|---|---|---|---|---|---|---|---|
| **BM'** | **Volume TWh** | ***Price £/MWh*** | **Cost £m** | **Volume TWh** | ***Price £/MWh*** | **Cost £m** | **Volume TWh** | ***Price £/MWh*** | **Cost £m** |
| Bids | -3.661 | *£29.06* | -£106.4 | -3.348 | *£28.09* | -£94.0 | -7.009 | *£28.59* | -£200.4 |
| Offers | 1.837 | *£82.48* | £151.5 | 1.429 | *£136.09* | £194.5 | 3.266 | *£105.94* | £346.0 |
| CND | | | -£2.0 | | | -£4.1 | | | -£6.1 |
| **Total BM** | **-1.824** | | **£43.1** | **-1.919** | | **£96.3** | **-3.743** | | **£139.5** |
| **NIA** | **Volume TWh** | ***Price £/MWh*** | **Cost £m** | **Volume TWh** | ***Price £/MWh*** | **Cost £m** | **Volume TWh** | ***Price £/MWh*** | **Cost £m** |
| Bids | -2.399 | *£20.14* | -£48.3 | -2.445 | *£20.10* | -£49.2 | -4.844 | *£20.12* | -£97.5 |
| Offers | 0.415 | *£133.38* | £55.4 | 0.747 | *£191.89* | £143.3 | 1.162 | *£170.99* | £198.7 |
| **Total NIA** | **-1.984** | | **£7.0** | **-1.698** | | **£94.2** | **-3.682** | | **£101.2** |
| **TRAD** | **Volume TWh** | ***Price £/MWh*** | **Cost £m** | **Volume TWh** | ***Price £/MWh*** | **Cost £m** | **Volume TWh** | ***Price £/MWh*** | **Cost £m** |
| Sales | -0.350 | *£18.67* | -£6.5 | -0.100 | *£34.23* | -£3.4 | -0.450 | *£22.13* | -£10.0 |
| Purchases | 0.290 | *£51.03* | £14.8 | 0.410 | *£103.66* | £42.5 | 0.700 | *£81.86* | £57.3 |
| **Total TRAD** | **-0.060** | | **£8.3** | **0.310** | | **£39.1** | **0.250** | | **£47.3** |

This table shows the forecast volumes, prices and costs of BM (in fact, CSOBM minus Constraints), NIA[51] and Trades for 2007/8, split into summer and winter.

[51] The forecast convention is that NIA is treated as a negative term within IBC. Thus this forecast is that costs of BM' + TRAD of £140 + 37m is offset by –£101m of NIA, yielding a total of £76m of IBMC+TRAD'.

## Ancillary Costs

*Methodology*

Historical costs and volumes of Ancillary Services (AS) are reported in our monthly Procurement Guidelines reports, and extensively to Ofgem, in particular as part of Ofgem's monitoring of our balancing activity during 2006/07. Our AS forecast model is consistent with this reporting, and with the approach adopted for other components of IBC.

Our forecast model starts from the historic prices and volumes seen over recent history, April 2005 onwards. The model then extrapolates prices and volumes, service-by-service, into the forecast period April 2007 to March 2008. Each individual Ancillary Service is discussed in the following sections. For reasons of confidentiality, some detail has been omitted from this public appendix and has been provided separately to Ofgem.

*Frequency Response*

The key driver of Frequency Response costs is expected to be the market pricing behaviour for Mandatory Frequency Response. Mandatory Frequency Response makes up approximately 60% of the Response volume procured by National Grid and is the prevailing price against which other Dynamic response services are procured. Our forecast cost of Frequency Response is therefore based on our view of price trends in mandatory Frequency Response. The forecast prices drive both the cost of Mandatory Response and our view of the likely cost of alternative sources of Frequency Response.

Prices have been submitted monthly under the current pricing arrangements since November 2005. Average accepted prices for mandatory Frequency Response are shown in the graph below. Significant additional detail on recent Frequency Response costs can be found within our Income Adjusting Event notice in relation to Cap047[52]. The latest response price data can be found on our Industry Information website, within the balancing services section.

At present, the main drivers for the observed changes (increases) in Mandatory Frequency Response since the introduction of CAP047 in November 2005 are not clear to us. Overall, up to May 2006 prices have followed a sustained upward trend, at an approximate average of increase of 7% per month. We have considered the following drivers but have not identified an underlying driver for this increase:

- If prices had been driven by fuel cost (or expected fuel cost, because prices are submitted in advance), then we would expect to have observed a sharp price

[52] This document is available via the following hyperlink: http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/15626_1c.pdf?wtfrom=/ofgem/work/index.jsp&section=/areasofwork/wholesalemarketmonitoring

increase, particularly for gas-fired generation, during the winter and then these prices to have reduced during the summer, reflecting trends in fuel costs. This has not occurred.

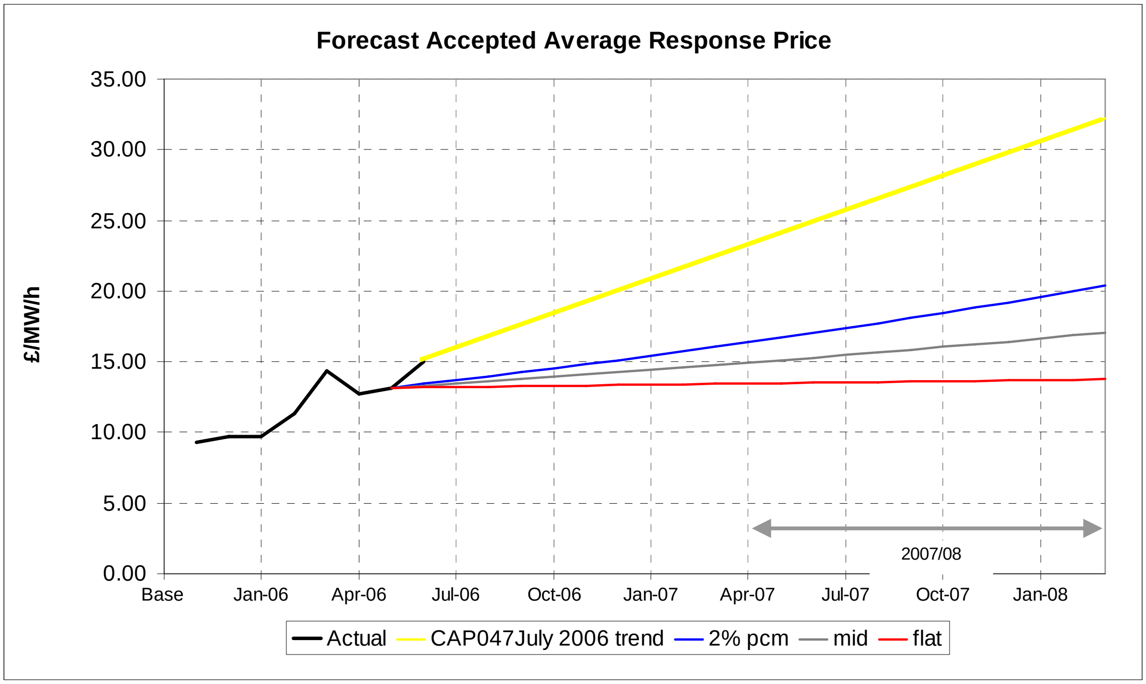
- If the main driver for the increase had been a systematic under-recovery of the costs of the true costs of response holding under the old mechanism, then we would expect to have observed a sharp step change immediately following the introduction of CAP047, followed by little movement in prices. Again, the observed sustained increase goes against this hypothesis.

- Also related to under-recovery, if the main driver for the price increase had been a systematic under-recovery of the costs of Response Energy, related to CAP107, we would expect to have observed a decline in price during the summer, as the cost of Response Energy provision reduced. This has not occurred.

- Sustained price increases could also be explained if National Grid had significantly increased the volume of Mandatory Response procured over the same period. However, the volume of Mandatory Response procured by National Grid has not increased significantly over the period November 2005 to July 2006.

The price trend observed may be the result of the combination of a number of drivers, including several of those discussed above. We will continue to analysis these price trends and it is likely that our view on future prices will change as we gain more experience.

In the absence of any clear driver, our forecast range of Mandatory Frequency Response prices is based on prices seen to date with a nominal forward extrapolation. We have extrapolated these through 2006/07 assuming only a small upward trend, much reduced from that seen to date, with the low end of the range reflecting a 0% real increase and the upper end of the range set by an increase of 2% per month from May 2006 (this compares to observed price rises of greater than 7% per month to date).




Our full forecast of Frequency Response costs has been provided separately to Ofgem. Overall, based on a mid-range price increase of 1% per month, we currently forecast of £106m for response costs in 2006/07. Taking a low price scenario (i.e. no rise in real prices from present day on), forecast response costs would be £90m. It should be noted that the price rise in June 2006 and the overall post CAP047 trend have not been referenced in this forecast. Our current high case gives a forecast cost in excess of £115m.

Within the forecast we have assumed that prices for alternative response procurement, such as Firm Frequency Response (FFR), will continue to vary broadly in line with prices available for Mandatory Frequency Response, allowing for savings to be delivered because of the Firm nature of the FFR service.

*Reactive Power*

The volume of reactive power utilised during 2005/06 outturned at 26.8Tvarh with the inclusion of Scottish Mvarh which are now paid under GB CUSC arrangements. We forecast no change in the total volume of GB reactive, either this or next year on last year. We expect the upward drivers of increased Wind generation and demand growth to be offset by despatch efficiencies, as we gain increasing experience of the Scottish system.

Following the implementation of CUSC amendment CAP045, the price of default reactive utilisation is now 50% indexed to power prices. Our forecast for Reactive Power costs is therefore based on a straight calculation of prices based on our forecast of power prices. Tenders seeking reactive market contracts factor in the full default price into their tendered prices.

The increase in power price for 2007/08 compared with the outturn power price for 2005/06, combined with a static year-on-year volume, result in our forecast of reactive costs rising from £55m in 2005/06 year to £64m next year, entirely as a result of power price variation. If power prices were to stabilise near to current levels, the 2007/08 figure would be closer to the £61m currently forecast for 2006/07.

*Standing Reserve*

For 2006/07, we have contracted a volume of 2,497MW of standing reserve, at a projected cost of £55m. This cost comprises £50m of availability fees (including a nominal £2m assumed for Supplemental Standing Reserve), plus £5m of utilisation payments to non BM providers paid via Ancillary.

For 2007/08, based on our procurement expectations we are forecasting a rise in expenditure to £65m. As this forecast is to be published ahead of the submission of Standing Reserve tenders, we do not consider it would be appropriate to comment further on the construction of this forecast cost. We have separately provided full details of this forecast Ofgem.

*Fast Reserve*

Costs for Ancillary Fast Reserve for 2005/06, across firm and optional sources, outturned at £36.4m. Our forecast for Ancillary Fast Reserve for 2006/07 is £37m, and for 2007/08 is £39m.

*Other Reserve*

Within Ancillary in 2005/06, we also spent £6.3m on other reserve services, such as Fast Start payments to OCGTs and pumped storage, which do not fit into the above categories. We forecast to spend £6.5m on Ancillary Other Reserve for 2006/07 and 2007/08.

*Cancelled Warming costs*

The cost of warming contracts outturned at £7.4m for 2005/06. This is much lower than historic levels of £15-30m for Warming costs. The reduction is due in part to the increase in dispatch of CCGT stations through PGBTs and in the BM, rather than through Warming contracts.

For 2007/08, we anticipate the same volume and price of activities by current providers. However, we anticipate that the roll-out of firm payment provisions as part of BM start-up will result in a transfer of £5m of costs from BM margin acceptances into increased warming payments under the new provisions. Therefore, our 2007/08 forecast is £12m.

*Black Start*

Costs for Black Start services for GB have outturned at £14.4m last year, and include the costs of Scottish providers, and refurbishment and testing of some existing providers. We forecast a rise in these costs for 2007/08 based on current negotiations which will result in payments next year. In addition, the costs of black start tests have increased in line with power prices. These two elements result in a forecast Black Start cost for 2007/08 of £18.5m.

Our forecast follows the current practice of four stations tested for Black Start each year, and we have assumed no changes in testing frequency that may result from initiatives on Black Start preparedness.

*Constraints*

Costs for Ancillary Constraints are included in the forecast of Constraints.

*SO-SO Energy*

The costs of 'SO to SO trades' across the French and Moyle Links, outturned at £12.0m in 2005/06. These costs interact strongly with costs both pre-Gate in the BM for Constraints, Margin and Footroom amongst others. For simplicity in this forecast, we preserve this cost of £12m in all future years. Variations in the costs of this service are handled by the driver impact on BM costs, analysed in the preceding sections.

*Ancillary Other*

Each year, we incur miscellaneous other Ancillary costs, which include Trading fees, and liabilities for services used which we do not manage to settle within-year. These costs have declined from approximately £5m for the first two years of NETA to £2m currently, and we forecast costs to remain at this level next year.

**Total Ancillary Forecast**

In summary, the main year-on-year variances and key points of the Ancillary forecast are:

- Frequency Response, costs driven by market pricing behaviour for mandatory frequency response;
- Reactive Power is indexed linked to wholesale price and hence will vary accordingly;
- Standing Reserve;

- The BM Start up service will replace the current Warming contract and is expected to shift some costs into Ancillary costs as fees will become firm fees under BM Start up (whereas warming fees are only paid following cancellation of the warming instruction where the unit is not subsequently synchronised).

Our mean forecast for Ancillary services is summarised in the table below.

**Summary of Forecast Ancillary Services Costs for 2006/07 and 2007/08 (£m)**

| | 2001/02 | 2002/03 | 2003/04 | 2004/05 | 2005/06 | 2006/07 | 2007/08 | Variance to 05/06 |
|---|---|---|---|---|---|---|---|---|
| **Reactive** | 38.1 | 33.0 | 33.5 | 36.7 | 54.7 | 61.0 | 64.0 | 9.3 |
| **Response** | 63.6 | 58.2 | 44.5 | 44.8 | 65.4 | 90.0 | 106.0 | 40.6 |
| **Fast Reserve** | 16.7 | 30.8 | 18.7 | 25.8 | 36.6 | 37.0 | 39.0 | 2.4 |
| **Standing Reserve** | 20.1 | 22.5 | 42.5 | 48.1 | 42.2 | 55.0 | 65.0 | 22.8 |
| **Other Reserve** | 6.6 | 4.5 | 4.2 | 5.0 | 6.3 | 6.5 | 6.5 | 0.2 |
| **Warming** | 9.0 | 30.4 | 21.1 | 16.3 | 7.4 | 12.0 | 12.0 | 4.6 |
| **Black Start** | 9.1 | 9.8 | 10.1 | 10.0 | 14.5 | 17.5 | 18.5 | 4.0 |
| **SO-SO** | 11.2 | 13.3 | 11.1 | 10.6 | 11.9 | 12.0 | 12.0 | 0.1 |
| **AS Other** | 6.7 | 10.7 | 2.9 | 1.2 | 1.0 | 2.0 | 2.0 | 1.0 |
| **Total** | **181.1** | **213.2** | **188.6** | **198.5** | **240.0** | **293.0** | **325.0** | **85.0** |
| | **(E&W)** | | | | **(GB)** | | | |

The table shows the historic costs of each service for 2001/02 to 2005/06 and our forecast for 2007/08. The historic years 2001/02 to 2004/05 are on an England & Wales basis, whereas the years from 2005/06 onwards are on a Great Britain basis.

### Constraint Costs

*Forecasting Approach*

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

- England & Wales
- Cheviot boundary
- Within Scotland

*England and Wales, Within Scotland*

At this stage of the year, we have an outline transmission outage programme for summer 2007 with preliminary studies of boundary limits. For both England & Wales and within-Scotland, we have reviewed these outline outages, against our experience of previous years.

Across the average of our typical constraint boundaries, this outage programme is neither more nor less onerous than the outage programme was for summer 2006 as of July 2005, or that for summer 2005 was in July 2004. In addition, the low change in generation disposition across 2005 to 2007 means that at present we have not changed our background constraint cost forecast for 2007/08 significantly from the cost of constraints experienced in 2005/06. These total £21m for England and Wales, and £28m for within Scotland.

*Cheviot*

We have re-run our Cheviot forecast model for 2007/8. The model has been calibrated, such that against 2005/06 data it yields the outturn cost of £30m. For 2007/8, key assumptions are:

- 1,270MW:1,590MW of Wind capacity installed summer : winter (There was already 760MW of capacity installed as of March 2006, and we only assume that 510MW of 700MW projected projects complete by March 2007.)

- 10 circuit-weeks of Cheviot outage, as planned for summer 2007.

- Cheviot boundary limits upped from previous values to 2,100 summer-intact and to 1,700MW summer-outage, in line with experience and calibration of summer 2005.

Against these assumptions, and including mitigations such as the availability of some intertripping services across the Cheviot boundary, our model forecasts a total Cheviot cost of £22.5m.

| Constraint Forecast Summary (2007/08) | |
|---|---|
| England and Wales | £21m |
| Cheviot | £22m |
| Internal Scotland | £28m |
| Total | £71m |

*Transmission Losses Forecast*

In the timescales for this forecast, we have not set up and run our normal TL forecasting model. There is very low turnover of generating plant, 2007/08 on 2005/06 (Dungeness A and Sizewell A are the only closures, and there is no new plant opening). Accordingly, we consider our previous forecast of 5.83TWh of transmission losses ('TL') for 2006/07 is also appropriate for 2007/08.

## Total IBC Forecast and Distribution

Our total forecast of IBC aggregating all forecast components is shown below. This table shows the differences between 2005/06 costs and our 2007/08 forecast.

Currently we estimate the risk range around this forecast at +/-£10m on power price variance from forward price and +/-£30m on BM pricing effects (e.g. aggressive offer prices). We also estimate an uncertainty of ±£20m on the pricing of Ancillary Services.

For Constraints, our analysis to date suggests that background constraint costs for England and Wales and within Scotland will be similar between 2005/06 and 2007/08 but that Cheviot constraint costs will fall to £22m.

The Transmission Loss Adjustment term is assumed at zero reflecting the net treatment of Transmission Losses.

For the components described above we have not firmly quantified the range of uncertainty around our central forecast, and have therefore documented a single forecast in the table shown.

For Ancillary Services, our central forecast includes the impact of our price movement assumptions. These have their most significant impact in the Standing Reserve, Frequency Response and Reactive forecasts. With regard to these we would point in particular to:

- Continued observed growth in Mandatory Frequency Response prices
- The relationship between Reactive Power prices and energy prices

A full summary of our forecast is shown in the table below.

| | 2005/06 Outturn | Movement | | 2007/08 F/cast |
|---|---|---|---|---|
| BM' | 168 | Severe March<br>Additional Firm Procurement<br>Increase in Summer Prices<br>Decrease in Winter Prices<br>Total | -17<br>-18<br>12<br>-5<br>-28 | 140 |
| Minus NIA | −104 | Net Price Effect | +3 | −101 |
| TRAD | 47 | | | 47 |
| AS | 240 | Mandatory Response Full Year Effect[53]<br>Mandatory Response Price Rises<br>Firm Response<br>Fast Reserve<br>Standing Reserve<br>Warming Contract Form<br>Reactive Prices<br>Black Start<br>Total | +17<br>+13<br>+11<br>+2<br>+23<br>+5<br>+9<br>+4<br>+85 | 325 |
| CONS | 82 | Reduction in Cheviot costs | -10 | 72 |
| TLA | -5.5 | Neutral Forecast | +5.5 | 0 |
| Total | 428 | | +55 | 483 |

This shows a total forecast cost of £483m. It can be seen that the main difference in costs between 2005/06 and 2006/07 are:

- A decline in BM costs due to the removal of the one-off effect of Rough failure seen in March 2005 and the reduction in Reserve cost due to additional Firm Reserve and Response procurement. This reduction is partially offset by cost increases resulting from higher summer forward prices for 2007.

- The effect of Frequency Response price rises to date, plus a small ongoing rise, on total Response costs resulting in cost of Mandatory and Firm Response procurement are forecast to rise by £13m and £11m respectively.

- Standing Reserve cost rises of £23m, additional information on this element has been provided confidentially to Ofgem.

- Reactive power costs increasing by £9m as a result of higher summer power prices, to which Reactive power prices are indexed.

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[53] For clarity, the rise in Frequency Response costs has been broken down to illustrate that part of the total £27m rise in year on year costs is due to the fact the 2005/06 saw only five months of CAP407 operation. The equivalent full year cost of CAP047, at prevailing 2005/06 prices, would have been £17m higher than that seen.

# Appendix 4 – External SO cost savings

## BSIS Savings Delivered by National Grid in 2005/06[54]

### Introduction

National Grid's break-even scheme target point for Incentivised Balancing Costs for 2005/06 was £377.5m. The outturn cost was £427.2m, a spend of £49.7m over the balance point. This means National Grid made a £9.9m loss under its BSIS scheme in 2005/06. Whilst costs for Electricity System Operation were in excess of Ofgem's expectations embodied in the BSIS 05/06 target this note records activities taken by National Grid to reduce the costs of system operation.

We identify the following cost-saving activities, which contributed to reducing costs during 2005/06:

- Constraint Management – Scotland and England and Wales;
- Refinements to Reserve Procurement ;
- Frequency Response procurement.

### Constraint Management

*England and Wales*

The pattern of generation, demand and asset availability across 2005/06 gave rise to constraint requirements that were broadly similar to those experienced in 2004/05. Nonetheless, we faced a typical pattern of potential local and regional constraints, and National Grid continued to devise new strategies to reduce the risks of incurring costs against them. These measures included

- Adopting new running arrangements at a number of critical substations
- Developing the analysis tools underpinning our understanding of market based risks for critical BMUs to enable more effective constraint management actions
- Adopting flexible working patterns to enable circuit outages with significant constraint cost risk to be taken optimally, and to also allow circuits to return to service at short notice

In particular our energy trading activity continued to deliver benefits against alternative balancing actions in the BM.

[54] The content of this appendix reflects in its entirety material submitted to us by NGET.

The sum of our records of these activities, recording the risk faced at the planning stage minus the outturn cost after management, totals £7.3m of constraint cost saving in England and Wales.

*Scotland*

2005/06 was the first year of operation of the GB market. Prior to Betta go-live constraint costs in Scotland were internalised within the Scottish Market Arrangements.

The new GB market presented heightened challenges for constraint management because the nature of the interconnection of circuits between the Scottish and England and Wales systems is such that there can be periods of time where constraints exist under intact network conditions. In addition, the tools, techniques and risk management approach for constraints in Scotland are tailored to take account of various factors that differentiate the issue of constraint cost management in Scotland from National Grid's approach in England and Wales. Principally in Scotland there is lower interconnectivity than in England and Wales and also National Grid is both the system operator and transmission asset owner in England and Wales whilst in Scotland National Grid has the single role of System Operator.

Within Scotland, significant savings have been achieved by National Grid's system operation activities working together with the Scottish transmission asset owners planning and system management teams. This has included the joint application of constraint management techniques to Scottish system operation in particular the selective application of short term ratings for transmission assets which has reduced the need for the system operator to take pre-fault constraint actions.

The sum of our records of these activities related to Scottish Transmission, recording the risk faced at the planning stage minus the outturn cost after management totals £16.3m of constraint cost saving in Scotland.

National Grid has submitted an Income Adjusting Event notice in respect of Scottish constraint costs for 2005/06 that goes into further detail concerning incurred Scottish constraint costs.

**Refinement of Reserve Requirements**

Our reserve requirements are regularly reviewed, and are set based on historic and expected plant behaviour and demand forecast uncertainty. We also review our application of dispatch of reserve and seek ways to reduce the costs of reserve held whilst maintaining security of supply. The costs for reserve in 2005/06 were considerably higher than in 2004/05 as marginal generation prices were significantly higher in 2005/06 than prior years.

During 2005/06 National Grid looked at its approach to the creation of reserve and, whilst the conclusion was that our reserve setting and holding policy and practise was appropriate, an opportunity was identified to reduce the need for committing to create reserve at time scales significantly ahead of real time. Contingency reserve requirements were reduced by 500MW at 12 and 6 hours ahead of real time during 2005/06 on 2004/05 levels. We have assessed the savings in reserve costs at approximately £2.7m.

**Response Costs**

In response to the anticipated increased level of response costs under CAP047 introduced part way through 2005/06, we have expanded our portfolio of contracts and developed new services for various response services. The development of new response products has been successful in that we have increased provider participation which has enabled National Grid to secure response service provision from new providers and develop a more liquid market in the provision of some types of response services:

In 2005/06, we introduced the new Firm Frequency Response competively tendered product which has helped to mitgate the impact of CAP047 on System operation costs.

At the introduction of CAP047 it quickly became clear that holding costs for mandatory dynamic response would rise significantly. This led to an increased focus in the area from our control room teams. They have managed trh system frequency in 2005/06 whilst holding significantly lower volumes of mandatory dynamic response. The volume in 2004/05 between 1st November 2004 – 31 March 2005 was 6,269 GWh whilst the corresponding value between 1st November 2005 – 31st March 2006 was 5,632 GWh. This has been achieved against a background of continued strong performance in terms of system frequency control. The standard deviation of frequency control is largely unchanged between 2004/05 and 2005/06 at 0.05845 and 0.05958 respectively.

Overall, these measures delivered approximately £2.9m of savings.

National Grid has submitted and Income Adjusting Event notice in respect of CAP047 related to response costs for 2005/06 which contains more information on National Grid' actions to manage frequency response.

**2005/06 BSIS Savings**

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

| | |
|---|---:|
| Constraint management England & Wales | £7.3m |
| Constraint management Scotland | £16.3m |
| Refinement of reserve requirements | £2.7m |
| New response contracts | £2.9m |
| TOTAL | £29.2m |

These savings of £29.2m show that we continue to deliver value to consumers through the incentivisation of balancing costs.  As our costs exceeded the break even point and moved into BSIS losses in 2005/06 the savings achieved represent an 80% saving passed to the market and a 20% reduction in BSIS losses to National Grid. In future years these savings will be passed fully through, as their benefit is reflected in future years' scheme targets.

# Appendix 5 – NGG's forecast of SO volumes and costs

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31st July 2006

**Formal information request under paragraph 1 of Standard Special Condition A26 of National Grid Gas Transmission's Licence in respect of the National Transmission System – Data requirements for Initial Proposals**

Dear Simon

Please find attached a response to your formal notice dated 4 July 2006 requesting information pursuant to paragraph 1 of Standard Special Condition A26 of National Grid Gas's Gas Transporter Licence in respect of the National Transmission System (NTS).

Whilst we have complied with the information request, it is important to note that considerable uncertainty still exists in relation to a number of areas all of which impact on the level and cost of system reserve services, these areas include:

- Supply uncertainty (UKCS and new import levels)
- Demand side response uncertainty
- Contestability and the future funding of LNG; and
- TO investment allowances.

Our view on the interaction of these factors on the expected volumes of gas system reserve for 2007/08 is detailed below.

***Expected levels of gas system reserve 2007/2008***

Our best view at this time of the expected volumes of gas system reserve for formula year 2007/8 is set out in the table below. Forecasts for a range of scenarios are given as the forecasts are crucially dependent on the supply and demand assumptions employed.

| 2007/8 GWh | | Supply Assumptions | |
|---|---|---|---|
| | | *Base Case* | *Base Case with 30MCM/d loss* |
| Demand Assumptions | *Unrestricted Demand* | **Medium case 1589** | High case 1922 |
| | *Restricted Demand* | Low case 1427 | Med/High case 1756 |

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***Scenarios***

**<u>Medium case</u>**

Our medium case forecast is 1589 GWh and is based on a reasonable set of supply and demand assumptions as set out below. The forecast in this scenario is lower than our 2006/07 requirement of 1648 GWh, as published in the Operating Margins Statement 2006/07 in March 2006, which was based on our 2005 supply and demand forecasts, where:

- supplies were reduced to 96% of the forecast;
- Demands did not factor in any demand side response; and
- 2005 winter operational experience was factored in respect of
    - Supply losses
    - Forecast demand change

*<u>Supply</u>*

The latest 2006 base case supply forecast has been used. This assumes an average availability of 90% of the base case flows for UKCS and imports, which is consistent with the analysis published in the Winter 2006/07 Consultation Document (May 2006). Storage supplies are assumed to be at 100% of capability. These appear reasonable assumptions based on UKCS historical performance and with new imports still largely unproven. This is a balanced approach to the likely supply levels rather than a reliance on optimistic assumptions that all potential supplies turn up at the same time; as such this approach gives us more confidence in the system reserve volumes derived being sufficient to cope with the scale of most unforeseen events within scope.

The supply forecast used in these scenarios assumes that some supplies will be delivered through Milford Haven importation terminals and some from Ormen Lange. However, to the extent that either of these projects do not result in deliveries we have assumed that the resulting supply shortfall will be made good by additional flows arriving through the interconnectors.

*<u>Demand</u>*

Our forecast is derived from the 2006 forecast 1 in 50 severe demand curve. Albeit it excludes the recently observed demand side response seen last year. We believe this to be the most reasonable approach until more evidence confirming the levels of demand side response under severe conditions becomes available. However, the underlying general demand contraction from previous year's forecasts has been included.

**<u>Low case scenario</u>**

*<u>Supply</u>*

The supply assumptions for this scenario are the same as the medium case.

*<u>Demand</u>*

The starting point for this scenario is the same as the medium case except that it assumes that the level of demand side response seen in 2005/6 will exist under severe conditions and consequently demands are lower than under the medium case scenario.

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**Medium/high case scenario**

*Supply*

The starting supply assumptions in this scenario are the same for the medium case except that it factors in a potential non delivery (supply loss) equal 30 mcm/d. This level of supply loss could be as a result of the late arrival of flows from sources such as Milford Haven or Ormen Lange. In this scenario we assume that flows from other supply sources do not increase to backfill the loss of supply leaving the system with a 30mcm/d deficit in supply.

*Demand*

The demand assumptions under this scenario are the same as those for the low case.

**High case scenario**

This scenario combines the least optimistic assumptions from the previous three scenarios to derive a system reserve volume that would be able to cater for a far wider range of events within the scope of system reserve.

*Supply*

The supply assumptions under this scenario are the same as for the medium/high case above.

*Demand*

The demand assumptions for this scenario are the same as those for the medium case.

***Other assumptions***

Other assumptions that remain constant throughout the scenarios are set out below.

*Recent operational performance*

Our modelling includes our most recent experience of supply losses; historical demand forecasting performance and assumes 10mcm/d linepack flexibility is available which is consistent with assumption used for 2006/07 bookings. There is no increase in the linepack assumption resulting from NTS re-inforcement, given that we do not invest in our network to provide system reserve per se. To use any other assumption would lead to the creation of a two tier network planning process; one for the physical network and one for the commercial network. The difference being a reflection of the degree to which parts of the network have been earmarked to only provide system reserve services.

*TO investment allowances*

Levels of OM are impacted by investments made within the network. National Grid Gas NTS notes from Ofgem's Initial Proposals document that considerable uncertainty exists as to which investments will ultimately be allowed within the TO RAV, and hence this may impact our forecasts presented herein. We have produced our forecasts based on an assumption that all investments we proposed in the FBPQ are allowed.

***Price uncertainty***

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In relation to the price element of system reserve, we believe that further dialogue will be required with Ofgem. Not least because having established the volume of system reserve services required by the NTS, we then need to consider where this requirement can be secured in order to meet our Safety Case and UNC obligations.

As part of the Transmission Price Control Review, we are aware that discussions are taking place in relation to the future funding of LNG. We believe that until the issues surrounding LNG funding have been resolved (which will ultimately affect the availability of LNG), we cannot determine a facility by facility requirement with any degree of firmness.

Furthermore, unless it is clear as to whether a price cap will be in place or not for services from our LNG facilities then it is difficult to know what price assumptions should be used given that we believe that the present C3 prices are inappropriate.

***Other areas requiring further consideration***

Whilst the data provided above fulfils the requirements of the formal information request, given Ofgem's recent "Invitation to submit views on National Grid Gas System Operator Incentives 2007-2008" published on 5 July 2006 and the significance of the System Operator incentives and Ofgem's intention to publish initial proposals for the 2007/08 incentive schemes to apply to each of the SO incentives in late September 2006, we would welcome early clarification from Ofgem as to the treatment of the remaining System Operator incentives listed below:

- Entry capacity buyback
- Residual gas balancing
    - Daily price incentive measure
    - Daily linepack incentive
- System balancing – gas costs (shrinkage)

If you have any questions on any of the above please do not hesitate to contact either Penny Garner or myself.

Yours sincerely,

Chris Bennett
Transmission Regulation Manager

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22nd August 2006

**National Grid Gas NTS's forecast of system balancing gas cost volumes for the period 2007/08**

Dear Haren

**Executive Summary**

Please find below National Grid Gas NTS's forecast in relation to the system balancing gas volumes for the period 2007/2008. The figures presented represent our best view at this time.

The overall structure of the response provides a background to the system balancing – gas cost incentive and provides a forecast range of volumes and assumptions by component for each of the system balancing gas cost elements for the period 2007/08, analysed using historical analysis and within the context of 2005/06 actual performance and 2006/2007 actual/forecast performance. For each component, we have provided Ofgem with a low, central and high case.

In advance of providing the forecast for 2007/08 the section below provides some, hopefully, helpful background to the incentive.

**Background**

The system balancing gas cost incentive relates to the cost of managing NTS shrinkage performance.

There are four components of NTS Shrinkage:

- Own Use Gas (OUG) – that gas used for compression
- Unaccounted for Gas (UAG) – that gas which remains after taking into account all measured inputs and outputs from the system, own use gas consumption, CV shrinkage and the daily change in NTS linepack.

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- Unbilled Energy (CV Shrinkage) – that energy which is unbilled due to CV capping under application of the Gas (calculation of Thermal Energy) Regulations 1996 and subsequently amended in 1997.
- Electricity costs for electric drive compressors

Prospective volumes were identified at the time of the last price control review and are specified in National Grid Gas NTS's Licence, with the cost target established by applying a single assumed price. The allowed volumes were set in 2002 for a five year period and derived by modelling future expected requirements based on historic relationships and for each component taking account of projections of future supplies and demand. The allowed (fixed) price was initially set in the Licence for 2002/03 and 2003/04. From 2004/05 onwards, the price is determined during the Gas Cost Reference Price (GCRP) period where forward quarterly NBP gas prices over the reference price period are used to calculate the allowed (reference) price.

**Forecast system balancing gas cost volumes for 2007/08**

Within the following section we have provided National Grid Gas NTS's forecast volumes (GWh) for the period 2007/2008 by component part. In arriving at our forecast the system balancing gas cost elements for the period 2007/2008 have been analysed using historical analysis and within the context of 2005/2006 actual performance and 2006/2007 actual/forecast performance and represent our best view at this time.

**Own Use Gas (OUG) – Volume (GWh)**

| Low | Central | High |
|---|---|---|
| 6096 | 6472 | 7066 |

**Commentary**

The **central case** for OUG requirement for 2007/08 has been determined using the latest 2006 base case supply forecast and assuming seasonal normal demand (SND) for this period. The analysis utilises multi linear regression techniques, with regression coefficients being determined from historic actual compressor fuel and supply/demand data. These are then applied to derive future projections.

The multi linear approach is a strong technique for future forecasts in instances where there are no major structural or supply changes to the NTS. Although there are uncertainties with the supply pattern in 2007/08, the current north to south transmission pattern is considered likely to continue to be dominant and only in later years is there significant uncertainty in the supply and demand patterns. There is however a small increase anticipated in OUG to take account of slightly higher interconnector and East Coast flows.

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Based on this analysis our central case forecast for OUG for 2007/08 is 6,472 GWh. This forecast compares to the 2005/06 outturn of 6,104 GWh, however, it should be noted that in 2005/06 the total gas demand was typically below average expected levels. (i.e. below seasonal normal demand (SND)). It should be noted that the central forecast still includes the general underlying demand contraction from previous years demand forecasts.

The **high case** forecast of 7,066 GWh is derived from the severe demand duration curve and associated base supply. The **low case** forecast of 6,096 GWh is derived by taking reference to 2004/05 and 2005/06 actual supply/demand data. The throughput over this period saw a 3% year on year reduction, which equated to a 5.8% year on year reduction in compressor fuel use over this period. In generating the low case forecast this recent reduction in OUG volume has been applied to our central case forecast.

In summary, at this stage we would maintain that **6,472 GWh** is our best view of OUG volumes in 2007/08, under seasonal normal demand conditions but taking into account the general underlying demand contraction from previous years demand forecasts. This compares with an allowance in 2005/06 of **7,245GWh.**

Within these OUG forecasts we have assumed that there is no additional change out to electric drive above that which already exists at Lockerley and Peterstow. This is consistent with our submission in the FBPQ. The issue of electric drives will clearly be an important factor for the later years in the next price control period.

**Unaccounted for Gas (UAG) – Volume (GWh)**

| Low | Central | High |
|---|---|---|
| 1022 | 1114 | 1788 |

**Commentary**

The **central case** UAG volume forecast for 2007/08 has been determined from a six (6) year average of annualised assessed UAG corrected for periods of exceptional periods of negative UAG in 2003 and 2005/06.

This central forecast of 1,114 GWh compares with the assessed total UAG for 2005/06 of 536 GWh. However, within the total of 536 GWh there are three months – January, February and March 2006 respectively that contained exceptional negative UAG. The concept of exceptional negative UAG is explained below.

The exceptional negative UAG criteria is defined as falling outside the lower band of the statistical process control methodology employed to assess UAG behaviour. This standard technique determines UAG volumes that fall outside two standard deviations

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around a 12 month rolling average. Over the period January to March 2006, using the standard deviation methodology above, a monthly UAG volume that was more negative than -75GWh, was considered exceptional. All three months in this period satisfied the criteria and therefore have been considered as exceptional negative UAG periods. The concept of normalising UAG i.e. removing the impact of exceptional negative UAG periods has been discussed in detail between National Grid Gas NTS, Ofgem and recognised experts. As such, for the purposes of determining a 'normalised' UAG volume for 2005/06, the exceptional negative UAG months have been substituted with UAG average figure (31 GWh) calculated from the previous twenty four (24) monthly UAG assessed volumes. This provides a 'normalised' annual UAG volume for 2005/06 of 1130 GWh,

Our **low case** of 1022GWh is based on our current forecast for 2006/07. The forecast UAG for 2006/07 is based on an aggregate of the first four (4) months of assessed UAG volumes to date of 757GWh, with an estimated August 2006 volume (239 GWh) based on 19 days actual UAG data prorated for the complete month. For the remaining seven (7) months we have used the 'normalised' volume for the same period of 2005/06 of 26 GWh (which equates to 1022 GWh).

A **high case** UAG forecast at 1,788 GWh for 2007/08 has been determined using the current run rate for 2006/2007 and discounting the winter months (October to April) by applying a scaling factor of 50% to reflect the historical trend of reduced UAG volumes in the winter months. (Applying the scaling factor, pulls down the pure run rate figure of 2,400 GWh down to 1,788 GWh).

**Unbilled Energy (CV Shrinkage)**

| Low | Central | High |
|---|---|---|
| 152 | 152 | 719 |

**Commentary**

The **central case** forecast for the CV Shrinkage requirement has been determined by employing comprehensive network analysis to define the inherent risk of CV capping. The same base case supply and demand profiles as used for the OUG central projection have been used. We are anticipating higher levels of unbilled energy at 152GWh for 2007/08, compared to the 2005/06 outturn at 85GWh, due to higher anticipated East Coast flows impacting both East Midlands and North East networks. We do not anticipate that the CV Shrinkage requirement will be lower than 152GWh, due to the anticipated flow patterns and widening of gas quality parameters increasing the risk of CV Shrinkage.

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The **high case** forecast of 719 GWh is possible if high CV gas flows from Grain LNG and Milford Haven over the 2007/08 period.

**Electric Compression – Volume (GWh)**

| Low | Central | High |
|---|---|---|
| 12 | 12 | 12 |

The 12GWh volume requirement is for the current electric compression on the NTS at Lockerley and Peterstow.

**Pricing**

As described the background section of this paper, the price element since 2004/05 has been determined during the Gas Cost Reference Price (GCRP) period where forward quarterly NBP gas prices over the reference price period are used to calculate the allowed (reference) price. We believe that it would be sensible to continue with this approach for the setting of the incentive going forward.

**Conclusion**

I look forward to working with you on developing the system balancing gas costs for the period 2007/08. In the meantime, if you have any questions on any of the above please do not hesitate to contact either Penny Garner or myself.

Yours sincerely,

Chris Bennett
Transmission Regulation Manager

# Appendix 6 – Incentivised balancing costs

## 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:

$$IBC = CSOBM + BSCC + TLA - NIA - OM - RT$$

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 charge[55] 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.

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.

[55] 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 7 – TPA forecast summary

1.1. This appendix provides a summary of the analysis conducted by TPA in respect of gas cost and gas reserve forecasts for 2007/08.

## Gas cost (shrinkage) forecast

### Own use gas (OUG)

1.2. TPA outlines three factors which could reduce OUG in 2007/08:

- The Langeled pipeline is expected to flow from October 2006. If this displaces 25-30 mcm/day of flows via Vesterled into the Total sub-terminal at St Fergus, gas compressor requirements will drop, as the Total terminal is the only St Fergus sub-terminal that requires gas compression. TPA assumes that if this reduces flows through the Total sub-terminal by 50%, St Fergus compressor usage will also drop by 50%.
- St Fergus flows from UKCS are significantly down in comparison to historical flows. Based on numbers provided in NG's winter outlook consultation, highest flows through St Fergus in 2005/06 were 98mcm/day compared to a forecast of 110mcm/day and the forecast for winter 2006/07 is a flow of 94mcm/day. TPA considers that this, in tandem with the first factor, will reduce the duty on compressors at Aberdeen, Kirriemuir, Avonbridge, Moffat and Carnforth.
- TPA considers that flows at Milford Haven will not need to use compression to get to centres of demand, reducing the requirement for compression at Peterstow.

1.3. Taking this into account, TPA developed the following revised forecast as follows:

- TPA Central takes the average of 2002/03 and 2003/04 actual OUG volumes (see table below) and scales this down by 30% to reflect the factors outlined above.
- TPA High provides a 10% sensitivity increase over the TPA Central case.
- TPA Low provides a 10% sensitivity decrease below the TPA Central case.

**TPA OUG forecasts for 2007/08**

| ▪ (GWh) | **Allowed OUG volume** | **Actual assessed OUG volume** | **TPA view** |
|---|---|---|---|
| 2002/03 | 6605 | 7028 | |
| 2003/04 | 6921 | 7363 | |
| 2004/05 | 7222 | 6484 | |
| 2005/06 | 7245 | 6104 | |
| 2006/07 | 7425 | Not provided | |
| 2007/08 - low | 6096 | | 4533 |
| 2007/08 - central | 6472 | | 5036 |
| 2007/08 - high | 7066 | | 5539 |

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**Unaccounted for gas (UAG)**

1.4. TPA developed the following forecast for UAG:

- TPA Central is based on the NGG low case.
- TPA High provides a 20% sensitivity increase over the TPA Central case.
- TPA Low provides a 20% sensitivity decrease below the TPA Central case.

**TPA UAG forecasts for 2007/08**

| (GWh) | **Allowed UAG volume** | **Actual assessed UAG volume** | **Actual assessed UAG net of meter error** | **TPA view** |
|---|---|---|---|---|
| 2002/03 | 1598 | 1200 | 292 | |
| 2003/04 | 1623 | -937 | -841 | |
| 2004/05 | 1633 | 200 | 565 | |
| 2005/06 | 1656 | 536 | 1130 | |
| 2006/07 | 1661 | 1022 | | |
| 2007/08 - low | 1022 | | | 820 |
| 2007/08 - central | 1114 | | | 1022 |
| 2007/08 - high | 1788 | | | 1230 |

**Unbilled energy (CV shrinkage)**

1.5. TPA accepts that an increase in unbilled energy could be possible but was unable to verify the extent of any increase. Based on this background, TPA developed the following forecast for unbilled energy:

- TPA Central is based on the NGG central case.
- TPA High provides a 20% sensitivity increase over the TPA Central case.

- TPA Low is based on the average allowed unbilled energy volume over recent years.

**TPA unbilled energy forecasts for 2007/08**

| (GWh) | Allowed unbilled energy volume | Actual assessed unbilled energy volume | TPA view |
|---|---|---|---|
| 2002/03 | 71 | 4 | |
| 2003/04 | 74 | -4 | |
| 2004/05 | 74 | 15 | |
| 2005/06 | 75 | 22 | |
| 2006/07 | 75 | Not provided | |
| 2007/08 - low | 152 | | 75 |
| 2007/08 - central | 152 | | 152 |
| 2007/08 - high | 719 | | 210 |

**Electric compression**

1.6. TPA does not consider that Peterstow will run once gas flows at Milford Haven. TPA has, therefore, developed the following forecast for electric compression:

- TPA Central is 6GWh, based on some use of Lockerley, removing estimated usage of Peterstow.
- TPA High provides a 2GWh sensitivity increase over the TPA Central case.
- TPA Low provides a 2GWh sensitivity decrease below the TPA Central case.

**TPA electric compression forecasts for 2007/08**

| (GWh) | Allowed electric compression volume | Actual electric compression volume | TPA view |
|---|---|---|---|
| 2007/08 - low | 12 | | 4 |
| 2007/08 - central | 12 | | 6 |
| 2007/08 - high | 12 | | 8 |

## Gas reserve forecast

1.7. TPA identified the following as possible factors which could lead to a reduction in NGG's reserve requirements with no changes to the Safety Case required.

**Potential reductions**

- The multiple event provision contains a large proportion of reserve requirement to cover for compressor trips. However, TPA considers that the introduction of new electric compressors should improve reliability and so reduce the reserve requirement to cover for compressor trips. TPA estimates that a reduction of 57GWh can be made to the overall requirement to reflect this.

- New importation projects will go ahead and provide additional supply. TPA considers that NGG has been overly conservative in its approach and considers that gas from new sources will be made available in the high demand Nov – Mar period, reducing reserve requirements. TPA also believes that modern LNG importation facilities (with redundancy, no gas processing and no gas compression) are highly reliable, much more so than offshore facilities or onshore gas processing plants. TPA estimates that a reduction of 25GWh can be made to reflect this.

- TPA believes that higher gas prices have reduced 1 in 50 demands and have made shippers increasingly take over the OM role themselves. TPA believes that increased shipper focus could lead to a reduction in reserve requirements of 14GWh.

**Possible areas of double provision**

- There is some overlap between OM categories e.g. Supply Losses and Orderly Rundown. NG has indicated that 350 GWh of LNG is required for Orderly Rundown, 356 GWh of LNG is provided to cover Major Events (which are primarily supply related and all for the winter only) and 100 GWh to cover for multiple event supply failures. TPA estimates that it would be possible to eliminate all the provision of OM for Major Events as any of these events would be so severe that if they occurred in winter there is a very high probability that a Gas Supply Emergency would have to be declared. The impact of removing this double provision is a reduction in OM of 356 GWh.

1.8. On this basis, TPA developed the following revised forecast around the NGG central case as follows:

- TPA High equals NG Central.

- TPA Central equals NG Central minus potential double counting (356GWh, as explained above).

- TPA low equals TPA Central minus TPA assessment of potential further OM reductions (96 GWh – the cumulative value of the potential reductions outlined above).

**TPA gas reserve forecasts for 2007/08**

| (GWh) | High | Central | Low |
|---|---|---|---|
| 2007/08 | 1589 | 1238 | 1142 |

1.9. The proposed reductions which are used to develop the TPA low and central cases are shown in the table below alongside the actual 2006/07 values:

**Breakdown of Current OM Requirement (GWh) by type and proposed changes for TPA Low Case**

| (GWh) | 2006/7 | Potential Adjustment | Reason |
|---|---|---|---|
| Major Events | 356 | -356 | Double counting |
| Multiple Events – Supply loss | 96 | -25 | Improved reliability of imports |
| Multiple Events – compressor trips | 227 | -57 | Reduced trips electrical comps |
| Multiple Events – forecast changes | 58 | -14 | Greater shipper focus caused by high gas prices |
| Orderly Rundown | 911 | 0 | |
| | | | |
| Total | 1648 | 452 | |

# 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 to 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.[56]

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 accordingly[57].

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 them[58]; and
- The interests of individuals who are disabled or chronically sick, of pensionable age, with low incomes, or residing in rural areas.[59]

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[56] entitled “Gas Supply” and “Electricity Supply” respectively.
[57] 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.
[58] 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.
[59] The Authority may have regard to other descriptions of consumers.

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 licensed[60] 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 Regulation[61] 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.

[60] or persons authorised by exemptions to carry on any activity.

[61] Council Regulation (EC) 1/2003

# Appendix 9 - Glossary

**B**

### Bid multiplier

The bid multiplier is defined as the ratio of the daily average accepted bid price and the day ahead average base-load power price.

### British Electricity Trading and Transmission Arrangements (BETTA)

The BETTA reforms, introduced on 01 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.

### Black Start

Certain power stations are required to have contingency provisions to enable them to restart should the system shut down - a "Black Start" capability. It is remunerated via capability payments indexed to inflation and forward prices. It is contracted for bilaterally.

**E**

### Electric compression

Electricity usage associated with the operation of electric drive compressors on the gas NTS.

### Enhanced reactive service

This describes a range of products delivering reactive power not provided via an obligatory arrangement. This is contracted for via market based arrangements.

**F**

### Free Headroom

This describes the volume across part loaded plant. It can also be thought of as the sum of spare capacity across all running generators.

### Frequency response

NGET has a statutory duty to maintain system frequency between +/- 1% of 50 hertz. The immediate second-to-second balancing to meet this requirement is provided by continuously modulating output. Mandatory frequency response is provided for via the CAP047 provisions, which enable providers to alter their holding prices. Further frequency response is provided by demand side and bid-offer acceptances which form commercial frequency response services.

Commercial frequency response is entered into between the SO and the relevant provider, with the provider being able to freely price for volume. Generally commercial frequency response is cheaper than mandatory response and is entered into via bilateral contract.

### 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 >= 25MW/minute and the reserve needs to be sustainable for 15 minutes. Entered into via tender process.

### Fast Start

Fast start is the ability of OCGT plant to ramp from standstill to its maximum rated output within five minutes of initiating a low frequency relay, or within seven minutes of a manual instruction. It comprises an availability fee and an utilisation fee. It is contracted bilaterally.

**I**

### 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).

**L**

### Linepack

The volume of gas within the NTS.

### LNG

Liquefied Natural Gas.

**M**

### Maxgen

This is an emergency service and is used to extract additional output beyond a unit’s normal operational range. It is contracted bilaterally with NGET, with submitted prices, volumes and “Xs” being provided on a monthly basis to NGET. This service is provided for under CAP071.

**N**

### NGET

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.

### NGG

National Grid Gas plc (NGG) is the SO for the main gas transmission system in GB, by virtue of holding the gas transporter licence in respect of the National Transmission System.

### NTS

The NTS (National Transmission System) is the high pressure gas network for the GB.

**O**

### OCM

The OCM (On-the-day Commodity Market) is a screen-based service enabling anonymous, financially cleared trading between market participants, including NGG.

### Offer multiplier

The offer multiplier is the ratio of the daily average accepted offer price and the day ahead average base-load power price.

### OM

OM (Operating Margin) gas is used by NGG to maintain system pressures under circumstances, including periods immediately after a supply loss or sharp change in demand, before other measures become effective, and in the event of plant failure or the orderly rundown of the system.

### OUG

OUG (Own Use Gas) is gas used for compression.

**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.

**S**

### SAP

SAP (System Average Price) is the average price set by all trades on the OCM on a given day.

### 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/performance fall below or exceed the target.

### Shipper

A company holding a shipper's licence granted by Ofgem. Shippers may buy gas from producers, sell it to suppliers and employ NGG to transport it to suppliers' customers. A shipper may also be licensed as a supplier.

### System Operator (SO)

NGET is the operator of the high voltage electricity transmission system for GB. NGG is the operator of the gas NTS for GB.

### 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.

### UAG

UAG (Unaccounted For Gas) is gas which remains after taking into account all measured inputs and outputs from the system, own use gas consumption, CV shrinkage and the daily change in NTS linepack.

**W**

### Warming

This service is used to decrease the notice period a unit needs to deliver power. It substantially increases the flexibility of plant on the system. Warming and hot standby contracts exist, in £/hr availability fees. When a warmed unit is instructed the warming payment falls away, but the hot standby fees remains (provided it has been initiated), provided for via bilateral agreement.

## 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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