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Review of Electricity and Gas System Operator Role, Functions and Incentives: Initial Thoughts

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Overview:

National Grid Electricity Transmission (NGET) is the System Operator (SO) for the electricity transmission system in Great Britain (GB), and National Grid Gas (NGG) is the SO for the gas transportation system. This document and the supplementary appendices set out our initial thoughts on the review of gas and electricity system operator functions and incentives.

This document invites views from interested parties on a number of questions relating to the activities of the SOs, and their current incentive schemes. It is important that the incentives on the SOs create the conditions for the efficient and economical operation of the system so as to minimise the costs that gas and electricity customers pay. Following consideration of respondents' views, we will issue a further consultation paper, setting out our views on the scope of the changes that we will implement for April 2008, and those changes that we will implement from April 2009.

Contact name and details: Lisa Martin and Vanja Munerati (gas)

Tel: 020 7901 7000

Email: gb.markets@ofgem.gov.uk

Team: GB Markets

Context

This project is part of our work to regulate markets effectively. In both gas and electricity we consider that it is important that the roles of the system operators are correctly identified and that they have the appropriate tools available to them to undertake these roles. Any interventions in the market by the system operators can lead to costs being incurred, both directly by the system operator and more widely by the market as a whole. Since customers ultimately bear these costs it is important to keep them as low as possible. Based on our experience over the past years, we remain of the view that the best way to achieve the lowest costs to customers is to provide the system operators with commercial incentives whereby they share some of the gains (losses) from cost reductions (increases).

Associated Documents

- National Grid Electricity Transmission and National Grid Gas System Operator Review, Ofgem, 18 May 2007

- National Grid Gas System Operator Incentives from 1 April 2007: Final proposals and statutory licence consultation, Ofgem, 21 March 2007

- National Grid Electricity Transmission System Operator incentives from 1 April 2007: Final proposals and statutory licence consultation, Ofgem, 27 February 2007

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Summary

Here we set out our initial thoughts on the review of gas and electricity system operator (SO) functions and incentives. This follows publication of an open letter in May 2007 that set out the terms of reference for this review.

The electricity and gas SOs play a pivotal role in the operation of these markets and are responsible for managing elements of the wholesale market costs. Ofgem is keen to hear industry views on whether the incentives on SO activities are both appropriate and effective.

This review will consider the form, scope and duration of external SO incentive schemes for gas and electricity and the provision of information by the system operators. The review will have two outputs: SO incentive schemes which will operate from 1 April 2008; and an approach to establishing more enduring SO incentive arrangements.

System Operation in the Electricity Market

The two primary responsibilities of the electricity SO are residual balancing (ensuring energy on the system balances in real time), and system balancing (maintaining the network within safe and secure operational limits). In carrying out these roles, the SO has the freedom to develop and use a wide range of tools and options to operate the system in an economic, efficient, and coordinated manner.

The electricity SO role is undertaken by National Grid Electricity Transmission (NGET). In undertaking this role, NGET incurs both internal and external costs. Internal SO costs do not fall within the scope of this review. External costs incurred by NGET in the operation of the electricity system in 2006/07 totalled over £550million (an increase from £247million in 2002/03). The main driver for this increase included the increase in the size of the market following BETTA, increased constraint costs, as well as high wholesale electricity and gas prices. Moving forwards, there are a number of industry developments that may affect the levels of these costs. These include policies relating to climate change, transmission access, and the cash out arrangements.

One of the questions to be answered through this review is whether it is in customers' interests to extend the duration of the incentive regime to more than one year. We believe that a longer term incentive regime could allow the SO to achieve additional savings through innovative actions based on a longer term planning horizon. This would also have benefits in terms of better regulation as it would reduce the regulatory burden that annual schemes create for Ofgem, the SOs and the industry.

However, the extent of the benefits of a longer term regime depends crucially on the drivers of SO costs and the impact of industry developments. Fixing long-term targets that are in customers' interests against the background of possible significant changes to the future regulatory arrangements (for instance to take account of increased distributed and/or renewable generation) may be problematic.

We also discuss whether the current single target methodology is appropriate and whether there are additional costs, such as the costs the SO will incur in operating the offshore networks to be developed, that should also be included.

System Operation in the Gas Market

As in electricity, the key responsibilities of the gas SO are residual gas balancing and system balancing. In fulfilling these roles, National Grid Gas (NGG) has a range of tools available to it, including use of linepack, trading on the on-the-day commodity market (OCM), optimising compressor use and booking of gas reserve.

In using these tools, the gas SO incurs significant costs, many of which are currently subject to incentive schemes. The largest category of cost relates to the purchase of shrinkage gas. In 2006/07 this cost totalled £114.5 million. Other major areas of cost incurred by the gas SO include the booking of gas reserve (close to £20m in 2006/07), and buying and selling gas to balance the system (approximately £28 million in 2006/07). In the future, the level of these costs may be affected by a range of factors including the pattern of gas flows on the NTS, improvements in information transparency and the introduction of contestability in the market for operating margins.

As for electricity, we must establish how feasible and practical it is to set long term incentives on the SO. A key area is the operation of the price incentive (which is designed to provide a commercial incentive to take balancing actions as close to market prices as possible) and the linepack incentive (which is designed to prevent the SO from carrying forward significant imbalances from one day to the next). In addition, we question whether NGG's requirements for gas reserve held at (relatively expensive) locational LNG storage facilities are justified and whether substitutable sources for gas reserve at these locations have been fully explored. We also review the current form of the residual balancing incentive and the information incentives.

Way Forward

We ask for the views of industry on all aspects of the functions of the electricity and gas SOs, as well as on the scope and form of the SO incentives.

It will not be feasible for all elements of this review to be finalised in time for implementation in April 2008. We therefore intend to separate out the work into two areas. One of these will deliver incentive schemes for April 2008. A second workstream will then address broader issues with the objective of implementing these changes from April 2009. In order to assist the development of these two separate workstreams, we will hold an Industry Workshop in late October, followed by publication of a further consultation document.

1. Introduction

Chapter Summary

This chapter provides a short background on the process so far. 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. During the consultation process for the electricity and gas SO incentives that were implemented on 1 April 2007, we indicated our plans to conduct a review of the SO roles of National Grid Electricity Transmission (NGET) and National Grid Gas (NGG), including the SO incentive schemes for gas and electricity to apply from April 2008 onwards. Further, in our December Initial Proposals Consultation Document, we published draft terms of reference for such a review. In our recently published Corporate Plan we also stated that we plan to conduct a full review of the roles of the SOs.

1.2. On 18 May 2007, we published an open letter announcing that we will be undertaking such a review during 2007. We attached the final terms of reference for the review as an appendix to that letter (see Appendix 5). We received two written responses to the open letter.[1] In the open letter we stated that the objective of the review will be to examine the effectiveness and appropriateness of existing arrangements, which will also assist in developing more enduring SO incentive schemes for the period from 1 April 2008. This "initial thoughts" consultation document is the next stage in meeting the objectives of the review.

Structure and approach

1.3. This document consists of three chapters. This chapter provides background, and outlines the process we are following in undertaking this review, the structure of the document and the way forward.

1.4. In Chapter 2 we discuss the role of the electricity SO, and its external incentive schemes. We outline the current role, the tools that the SO has available to it in order to undertake that role and how future industry developments may impact on

[1] Available from the Ofgem website, www.ofgem.gov.uk.

that role. We also discuss how the SO has performed under previous incentive schemes, outline the current scheme and discuss the possible parameters of future incentive schemes. Similarly, in Chapter 3 we discuss the role of the gas SO, and its external incentive schemes. Further information is provided in appendices to this document and in a separate supplementary document. These include two appendices, one in respect of electricity and one in respect of gas, from National Grid which provide its thoughts on the scope of this review and the key areas to be considered.

Emerging Policy Directions

1.5. As we outlined in our May open letter and as discussed further in Chapters 2 and 3, there are a number of ongoing issues that will need to be considered in parallel with this review. One key area is European policy, in particular, in respect of the role of the SO and the Commission's proposals on unbundling.

1.6. The European Commission is currently drafting a “3rd package” of EU energy liberalisation legislation, which is designed to tackle some of the problems identified in their Energy Sector Inquiry. Further unbundling of transmission may be a core element of this (the existing Directives only require legal unbundling). The options currently being examined include requiring either: ownership unbundling, or the establishment of an independent system operator. Draft proposals will be published by late September 2007 and the proposals will then enter Council/EP negotiations, which can take upwards of two years.

1.7. Although the UK has one of the most developed unbundled regimes in the EU, further domestic change once the proposals are finally agreed cannot be ruled out. We therefore need to ensure that the outcome of this review is consistent with the development of European policy.

Comparison of risks and returns on TO and SO businesses

1.8. We consider that it is appropriate to develop SO incentives schemes that provide the SOs in both gas and electricity with an appropriate balance of risk and rewards. One way to consider what may be an appropriate balance is to consider the returns received by the SO businesses compared with other regulated businesses, such as those of the transmission owners (TOs).

1.9. In terms of risk, TO businesses are usually viewed as being low risk, with this being taken into consideration at the setting of each price control (reflected in the allowed cost of capital). In contrast, returns from SO activities are determined through the operation of sophisticated incentive schemes and there is greater uncertainty (and potentially volatility) in the actual level of SO returns each year.

1.10. It is vital when considering future incentive schemes to ensure that the risks and rewards that they provide for provide an appropriate balance for the SO and also for customers, who ultimately pay for the costs of system operation.

Way Forward

1.11. Throughout this document, we pose a series of questions concerning the role of the SOs and their inventive schemes. However, these questions should not be seen as exhaustive, and we are interested in respondents' views on any aspect of the operation of the gas and electricity markets in respect of the SOs. In responding to this document, please can you be clear as to whether your comments apply to the gas and/or electricity arrangements.

1.12. Responses should be sent to gb.markets@ofgem.gov.uk, to be received no later than 28 September 2007. Further details of how to respond can be found in Appendix 1.

1.13. We will consider all responses to this document in developing the next steps. These next steps are likely to include an Industry Workshop in late October and a further consultation document to be issued subsequent to the Workshop, at which stage we will separate out the review into the two elements highlighted in the open letter:

- A workstream that will deliver the necessary changes for April 2008 (including specification of gas and electricity incentives, and critical aspects of these incentives that require review); and
- A parallel workstream that will address broader issues relating to the SO functions and associated incentives, with the objective of implementing broader changes from April 2009 (potentially applying through to the end of the current price controls in March 2012).

2. System Operation in the Electricity Market

Chapter Summary

This chapter provides details of the role of the SO in the electricity market and how the SO is incentivised to undertake that role in an economic and efficient manner. We provide background to the current role of the SO and the tools available to it to fulfil that role. We also provide details of the historic costs incurred by the SO and discuss the industry developments that are likely to impact on those costs in the future. In the second part of this chapter we provide details of the incentive schemes that have been placed on the SO and how it has performed against these schemes. We then discuss the development of future SO incentive schemes.

Question Box

Question 1: Do the current roles and functions of the SO ensure that the SO is able to operate the electricity transmission system in the most efficient and economic manner? If not, what changes do you consider should be made to the roles and functions of the SO such that it is better able to operate the electricity transmission system in the most efficient and economic manner?

Question 2: Do you consider that it is appropriate that only the SO can propose modifications to the Statements that the SO is required to have in place under C16 of its transmission licence? Do you think that market participants should also be able to propose modifications to these Statements and should they sit elsewhere, for example in the BSC?

Question 3: Do you consider that the costs incurred by NGET in its role as electricity SO represent the costs that would have been incurred by an economic and efficient SO? Are there particular areas where you consider that NGET has not incurred costs economically and efficiently? If so, please provide details.

Question 4: Do you agree that through BSUoS is the most appropriate way to recover the costs incurred by the SO? If not, please provide details of how these costs should be recovered.

Question 5: Do you consider that previous SO incentive schemes have been effective in ensuring that NGET as SO has operated the electricity system in an efficient and economic manner and managed the external costs of operating the system effectively? To what extent was the increased level of system operation costs incurred by the SO in 2006/07 attributable to the absence of an incentive scheme for that period? Please provide details of any areas where you consider that the SO incentive schemes have not been effective.

Question 6: Do you consider that a sliding scale scheme is the most appropriate way for an SO incentive scheme to operate? If not, please indicate what you consider to be a more appropriate type of scheme.

Question 7: Do you consider the use of the Net Imbalance Adjustment to be an appropriate way of adjusting for the costs resulting from market participants' actions that the SO has little control over? If not, how could this adjustment be improved?

Question 8: Is it appropriate for participants (including the SO) to have the ability to raise Income Adjusting Events when unexpected events occur resulting in increased or decreased costs? If not, how could such cost uncertainties be addressed under an incentive scheme?

Question 9: Do you consider that the costs of operating offshore networks should be included in the SO incentive scheme? Are there any other additional elements that you consider should be included? Are there elements that are currently included in the scheme which should be removed?

Question 10: Do you think it is appropriate to consider unbundling the electricity SO incentive scheme? If so, which areas do you consider should be separated out and how might the SO be incentivised in these circumstances?

Question 11: Would longer term SO incentive schemes provide greater opportunities for investment that ought over the longer term to result in greater net efficiencies in SO costs?

Question 12: If we were to consider a longer term SO incentive schemes, what are the key drivers of SO costs that would need to be considered over the longer period? In what way could these drivers be captured in the incentive scheme?

Question 13: What are the key developments that will affect future System Operator costs? How will these developments impact on costs?

Question 14: Are there areas in which the current transmission losses incentive scheme could be enhanced to improve further the incentives on the SO to operate the electricity transmission system in an efficient and economic manner?

Question 15: What additional market information do you consider should be made available to the market by the System Operator, and vice versa? Please explain how this information would improve system operation and market efficiency?

Question 16: Is there sufficient transparency surrounding the SO incentives both in terms of the process for setting the incentive parameters and in terms of the information on costs provided by NGET? If not, what additional information do you consider should be made available?

Question 17: Do you consider it appropriate that the electricity SO should have quality of information incentives placed on it (as is the case with the gas SO)? If so, how should the SO be incentivised?

Introduction

2.1. This chapter provides details of the role of the SO in the electricity market and how the SO is incentivised. The discussion is structured in four parts:

- role of the SO - which describes the role and costs incurred by the SO;
- SO incentive schemes - which sets out the experience of operating the incentive arrangements;
- future incentive schemes - which considers the issues surrounding the design of future arrangements; and
- transparency and information provision - which describes this aspect of the SO's role.

Role of the System Operator

Current industry set up

2.2. On 1 April 2005, the British Electricity Trading and Transmission Arrangements (BETTA) were introduced. BETTA introduced a single set of transmission and trading arrangements across Great Britain (GB). With the introduction of BETTA previously combined transmission activities were separated into system operation activities and transmission ownership activities. With the GB system operator (National Grid Electricity Transmission, NGET) being responsible for system operation activities on a GB basis and the three existing transmission licensees being responsible for transmission ownership activities in the areas based upon their existing licensed areas: England and Wales for NGET, southern Scotland for SP Transmission Limited (SPT) and northern Scotland for Scottish Hydro-Electric Transmission Limited (SHETL).

2.3. The Energy Act 2004 (the Energy Act) provided powers for the Secretary of State for Trade and Industry to put in place new regulatory arrangements for offshore electricity transmission to meet the requirements of new offshore wind electricity generation stations. NGET has been appointed designate SO for UK offshore transmission networks by the Secretary of State.

2.4. In Appendix 6 we provide a detailed description of the legislative and regulatory framework within which the electricity SO operates. This is included for reference; however we would welcome any views that respondents have on whether this framework remains appropriate in the context of the issues addressed in this chapter.

Role of the System Operator

2.5. The role of the SO is to ensure the safe, secure and economic operation of the system at all times. Thus, the SO is responsible for:

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

Energy Balancing

2.6. The primary responsibility for energy balancing lies with market participants (generators, suppliers, traders and customers) who have commercial incentives, created by the cash out regime,[2] to achieve energy balance.

2.7. Under the rules of the Balancing and Settlement Code (BSC), Suppliers and Generators are in a position of imbalance if their notified contract volume does not match their metered volume in any Settlement Period (half hour), i.e. they are producing (or consuming) electricity which has not been sold (or bought) and is therefore not covered by contracts. Imbalance settlement (or cash out), is designed so that any electricity produced or consumed that is not covered by contracts is paid for, or charged, at a cost reflective price. The arrangements are designed to target the costs that the SO has incurred in buying and selling electricity to match generation and demand onto those Parties that are in imbalance, i.e. those Parties on behalf of which the SO has taken electricity balancing actions.

2.8. Via exposure to imbalance prices, suppliers and generators face commercial incentives to contract ahead of the Balancing Mechanism. The trading arrangements give market participants the freedom to choose when and how to enter such contracts. However, imbalances left to the day will tend to be met by generators or demand side participants that have relatively high costs, compared to the prices that could have been obtained by contracting further in advance, including trading in the forward markets.

2.9. The SO's role is primarily one of residual balancer and is defined in terms of what other market participants cannot, or cannot at present, efficiently undertake through existing trading and market mechanisms. In this role, the SO is responsible for:

- ensuring that demand and supply are balanced on a moment by moment basis;
- managing the short term physical consequences of any plant failures;
- managing the short term physical consequences of any unexpected increases/decreases in demand; and

[2] Since the introduction of NETA in March 2001, there have been a number of modifications to the calculation of imbalance prices. As a result of concerns that the current cash out regime may not be providing the appropriate incentives to market participants, and also the piecemeal way that possible changes to the cash out regime are proposed, in February 2007 Ofgem launched a review of the cash out regime.

- the delivery of information back to the market.

System Balancing

2.10. The SO's role in terms of System Balancing requires it to take actions to ensure that the transmission system remains within safe technical and operating limits. The System Balancing role comprises two elements:

- **System management:** The SO maintains system stability by using a range of balancing services, such as reactive power and frequency response
- **Constraint management:** The SO takes actions to resolve constraints on the transmission system. These occur when there is insufficient 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.

2.11. Under the terms of its transmission licence, the SO is required to consider the most efficient mechanism by which to deliver its obligations. The SO should not only consider the most economic method and timing of procurement, but also the risk that it will be unable to balance the system in the short term should the energy required to do so be unavailable close to real time.

Services available to the System Operator

2.12. In the previous section, we discussed the functions of the SO in terms of energy balancing and system balancing. However, currently, it is often the case that the SO will take a single action that may assist in resolving both an energy imbalance and a system issue. A number of concerns have been raised regarding the SO's ability to do this. These concerns relate to the way in which the costs incurred by the SO affect the cash out price. Concerns have also been raised in relation to the lack of transparency of such actions, in that it is often unclear to market participants the reasons why the SO has taken the particular action.

2.13. The services that the SO has available to it to balance the transmission system constitute Balancing Services. These are defined in the Transmission Licence as: ancillary services, offers and bids made into the balancing mechanism and other services.

Procurement of Balancing Services

2.14. Where competition exists and it is efficient to do so, the SO will procure Balancing Services competitively and via a transparent process.

2.15. In order to fulfil this requirement, as outlined in Appendix 6, under standard condition C16 of its transmission licence, the SO is obliged to have in place four documents; these include the Procurement Guidelines and the Balancing Principles Statement. These statements may only be modified in accordance with the process set out in Standard Condition C16, under which only the licensee is able to propose modifications.

2.16. The SO may also agree non-discriminatory, bilateral contracts with service providers the terms of which should be consistent with its licence obligations. The Procurement Guidelines state that, in such circumstances, the SO will contact those service providers whom it believes are capable of providing the required service or who have expressed an interest in providing the service.

2.17. As outlined in the Legislative and Regulatory Appendix, the SO's procurement of Balancing Services is also constrained by a prohibition on purchasing or acquiring electricity other than for the purposes of coordinating and directing the flow of electricity onto and over the GB transmission system.[3] Appendix 7 provides further details on the services available to the SO.

Costs incurred by the System Operator

2.18. The SO's costs for balancing the system can be divided into internal and external costs. The SO's internal costs include the costs of its control centre, systems and staff. Ofgem has set an incentive scheme[4] to cover NGET's internal SO costs until March 2012, therefore these costs are not the subject of this consultation. The SO's external costs cover the costs of balancing services contracts and electricity purchases and sales for balancing purposes. Ofgem set an incentive scheme to cover NGET's external SO costs for the period from 1 April 2007 to 31 March 2008. This scheme is outlined in the second half of this chapter.

2.19. The SO's costs are in general driven by a combination of factors which impact on power prices and the volume of energy and system balancing services required by the SO. The volume of balancing services required is driven by factors such as participants' physical positions, the weather and the severity of winter conditions and more recently the increasingly warmer summers and their impact on the air cooling load. Key drivers of the SO's costs are:

- forward wholesale electricity prices - driven by factors such as generation fuel prices;
- balancing mechanism prices - average accepted bid and offer prices;
- market pricing of Ancillary Services such as Reserve and in recent years Frequency Response;
- net imbalance volume or market length[5];

[3] This prohibition is contained in standard condition C2 of the transmission licence.
[4] 'National Grid Electricity Transmission System Operator Incentives from 1 April 2007: Final proposals and statutory licence consultation' Ofgem, 27 February 2007.
[5] Net imbalance volume (NIV) is a measure of the net energy imbalance position of the market and is calculated as the net volume of balancing actions taken by the System Operator in the Balancing Mechanism and pre-Gate Closure. The NIV determines the volume and therefore

- free headroom - the level of part-loaded plant delivered by the market at gate closure; and
- system constraints - Resulting from transmission network limitations (which may be caused by network faults or maintenance) requiring the SO to take actions to constrain off generation at one location and actions to constrain on generation at a different point on the system.

Actual costs incurred

2.20. Table 2.1 below shows the breakdown of annual balancing costs by service from 2001/02 to 2006/07. The table shows that total balancing costs have increased year on year since 2001/02.

2.21. To date, the biggest year-on-year increase in costs has been between the costs incurred under NETA in 2004/5 and the costs incurred in 2005/06 the first year following the establishment of BETTA, when costs rose by £235 million. A number of factors contributed to this increase. The extension of the market (to include Scottish generation and demand) led directly to increased constraint costs. Other factors impacting on costs in 2005/06 were the outtage at the Rough Gas Storage facility in March 2006, high wholesale electricity and gas prices particularly in winter 2005 and increases in the holding prices of Frequency Response following implementation of CAP047.[6] In 2006/07 Scottish constraint costs and Frequency Response holding prices continued to be key cost drivers.

the costs of Bids and Offers which the SO has to take to balance the market. It also affects the level of operating margin available to the SO at Gate Closure. The Net Imbalance Adjustment term offsets the costs of the actions taken for energy balancing and is discussed in the section on the SO incentive schemes later in this document.

[6] The introduction of an amendment to the CUSC, CAP047, on 1 November 2005 removed the administered 'cost reflective' basis for setting holding payment prices. Following this change, generators were able to price freely this aspect of their mandatory frequency service.

Table 2.1: Breakdown of annual balancing costs by service[7] before any adjustment for Net Imbalance and Transmission Losses

£ m[8]		2001/02	2002/03	2003/04	2004/05	2005/06	2006/07
Balancing Services	Reactive Power	38.1	33.0	33.5	36.7	54.5	53.1
	Standing res.	20.1	22.5	29.6	32.7	41.2	57.6
	SSR	0	0	12.9	15.4	1.6	1.7
	Frequency resp.	63.8	58.2	44.8	44.8	66.3	124.9
	Fast Start	4.5	4.2	4.0	4.2	4.3	3.6
	Black Start	9.1	9.8	10.1	9.9	14.5	15.5
	Warming	9.4	30.4	21.1	16.2	7.4	11.9
	Fast Reserve	16.0	30.8	18.7	25.8	36.7	38.8
	SO to SO	2.8	3.5	9.0	10.3	12.6	21.2
	Intertrips	3.5	11.5	0.0	0.5	0.1	43.3
	All other services	5.3	7.5	8.7	9.0	10.1	3.0
Trades	Forward trading	-22.0	-18.0	8.8	11.1	34.2	29.8
	PGBT's			4.7	2.4	13.1	3.1
Total		150.6	193.4	205.9	218.9	296.6	407.5
Balancing Mechanism costs		65.7	58.5	74.5	83.1	240.5	143.2
TOTAL Balancing Costs		216.3	246.6	280.4	302.0	537.1	550.7
% Change year on year			14.0	13.7	7.7	77.8	2.5

2.22. Table 2.2 below shows the annual costs of resolving constraints since 2001/02 and NGET forecasts for 2007/08. These costs include all balancing services contracts costs and Balancing Mechanism costs incurred as a result of resolving constraints and are included in the total Balancing Costs for each year in Table 2.1 above. These costs have increased significantly following the implementation of BETTA as a result of constraints on the Scottish transmission system or on the Scotland to England Boundary.

[7] This table does not include the Net Imbalance Adjustment term or the Transmission Losses Adjustment term which impact on the SO's incentives scheme and are discussed later in the document.
[8] All costs in money of the day.

Table 2.2 Annual Costs of Constraints

£ m	2001/02[9]	2002/3	2003/4	2004/5	2005/6	2006/7
England & Wales	9.9	28	31.6	15.1	19.6	28.6
Cheviot Boundary[10]	-	-	-	-	31.6	24.9
Within Scotland	-	-	-	-	28.5	54.6
GB Total	-	-	-	-	79.7	108.1

Recovery of costs incurred by the SO

2.23. The SO's costs (both internal and external) are recovered from market participants via the Balancing Services Use of System charges (BSUoS). BSUoS charges also include any SO incentive payments (or receipts). BSUoS charges are calculated on a half hourly basis and are based on each participant's metered usage relative to the total use of the system.

2.24. As table 2.3 shows, BSUoS charges measured in £/MWh remained fairly stable year on year from 2001/02 to 2004/05 but that there was a significant increase (more than 44 per cent) in 2005/06 over and above 2004/05 BSUoS charges. This step change in BSUoS charges continued into 2006/07 as the level of SO costs continued to increase. These increases far outweighed the increase in the volume of the market resulting from the implementation of BETTA.

Table 2.3: BSUoS charges

	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07
BSUoS (Average Balancing Services Price) £/MWh	0.57	0.62	0.61	0.61	0.88	0.95
Year on Year change (%)		8.8	-1.6	0.0	44.3	8.0

System Operator Incentive Schemes

2.25. The objective of the SO incentive schemes is to create appropriate commercial incentives for the SO to efficiently manage the costs of system operation on behalf of customers. The SO incentives are intended to benefit customers in two ways. First, they align the interests of the SO with those of customers, and second they transfer

[9] All costs in money of the day
[10] Scotland to England Boundary previously known as the Scotland to England Interconnector prior to BETTA

some of the risk associated with higher balancing costs from customers to the SO, who is better placed to manage them on customers' behalf. SO incentive schemes are currently implemented via modifications to the SO's transmission licence. As with all licence modifications, any proposal by the Authority requires the consent of the licensee in order for the modification to come into effect.

Historical schemes

2.26. An SO incentive scheme in some form has been in place since 1994. Prior to the introduction of an SO incentive scheme the total cost of balancing the system was passed directly through to customers.

2.27. Since the introduction of the New Electricity Trading Arrangements (NETA), the terms of the schemes have been negotiated annually between the SO and the Authority and have been for the duration of 12 months. A financial target is set for the SO which is a balanced expectation of the costs of operating the system in the relevant 12 month period. The SO is incentivised to act efficiently and out-perform the target because it shares an agreed proportion of the cost savings below the target. Conversely, if actual costs are above the target, the SO is charged a proportion of the additional costs. Overall gains or losses are limited by a cap on payments and a floor on losses, i.e. a so called sliding scale or profit sharing scheme.

Net Imbalance Adjustment

2.28. The SO incurs costs as a result of the actions it takes to ensure the system remains in balance (energy balancing). However, the SO has little control over the extent to which market participants choose not to balance their own positions. To provide the SO with some protection against the cost of market participant imbalance, the SO incentive includes a "Net Imbalance Adjustment" (NIA) component. The NIA is subtracted from the costs that the SO incurs as a proxy for the costs resulting from market participants being out of balance. The NIA also provides the SO with some protection against wholesale price movements.

2.29. The NIA is derived by multiplying the system imbalance volume by the Net Imbalance Volume Reference Price (NIRP) for each Settlement Period. The first stage in deriving the NIRP is to calculate the Single Price Net Imbalance Volume Reference Price (SPNIRP) for the Settlement Period, using power exchange prices. A variable price adjustment is then applied to SPNIRP to give NIRP. When the system is long (i.e. the SO needs to sell in order to balance the system) SPNIRP is multiplied by 0.5, whereas when the system is short (i.e. the SO needs to buy in order to balance the system) it is multiplied by 2.5.

Transmission losses

2.30. The SO incentive scheme includes a transmission losses sub-target. Since 2005 the incentive on transmission losses has focused on net transmission losses, or the difference between actual losses and an agreed target. If the SO "beats" the target it receives a payment which is deducted from its costs. If actual losses exceed the target it faces a cost which is added to its costs. The calculation of this payment (or cost) is made by multiplying the difference between the actual and target losses by the Transmission Losses Reference Price (TLRP). The SO is therefore incentivised to minimise the volume of transmission losses but it is accepted that a certain level of losses is inevitable given the distribution of generation and demand.

2.31. In 2005/06 transmission losses outturned 190 GWh below the target of 5790 GWh resulting in a £5.5 million reduction in total SO Incentivised Balancing Costs whilst in 2006/07 losses were 311.4 GWh above the 5790 GWh target increasing IBC by £9 million.

Historical targets and performance

2.32. Table 2.4 summarises information on the incentive schemes implemented since NETA[11]. These numbers are inclusive of transmission losses and the Net Imbalance Adjustment (NIA), see below.

Table 2.4 Summary of incentive schemes in place since 2001[12]

£ m	Target Costs	Sharing factors		Cap	Floor	Outturn Costs	Payments
		Upside (%)	Downside (%)				
2001/02	382	40	12	46.3	-15.4	263.04	46.3
2002/03	367	60	50	60	-45	285.57	48.6
2003/04	340	50	50	40	-40	280.96	32.2
2004/05	320	40	40	40	-40	289.42	12.2
2005/06	378	40	20	40	-20	427.27	-4.0

2.33. For the four years from 2001/02 to 2004/05, the overall variation in incentivised balancing costs, was fairly stable in a range of £260 – £290 million, with the SO outperforming these incentive targets in each year. In aggregate over those four years, the SO received bonus payments of £135 million for outperforming its incentive targets. NGET did not meet the incentive target in 2005/06, and experienced its first penalty under the incentive scheme. In 2006/07, when no incentive scheme was in place, outturn costs were £495 million, significantly higher than in previous years.

[11] In 2005/06 the target was increased to reflect the widening of the scope of NGET's role as SO for the whole of GB following the introduction of BETTA. There was no external SO incentive scheme in place during 2006/07 because the SO did not consent to the license modifications required to implement Ofgem's incentive scheme proposals.
[12] All figures in money of the day. Figures also reflect incentive payments following the impact of any Income Adjusting Events, which are discussed in the following section.

Income Adjusting Events (IAEs)

2.34. The Income Adjusting Event (IAE) provisions are intended to provide protection for both the SO and transmission system users in case an event, or set of circumstances, occur that result in unanticipated SO costs or savings. The IAE provisions are detailed in special condition AA5A part 2(i) paragraph 10-12 of the SO's transmission licence. This outlines what constitutes an IAE, and the processes that must be followed by all relevant parties in giving notice of a proposed IAE and making a determination on the proposed IAE. An IAE may arise from any of the following:

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

2.35. Any BSC Party may submit notices to the Authority of proposed IAEs where outturn costs are materially different to those allowed under the incentive scheme. Ensuring that IAEs are treated in an appropriate manner will be particularly important if it is judged appropriate to extend the duration of the incentive mechanism.

2.36. To date only NGET has submitted notices of IAEs to the Authority. On each occasion Ofgem consulted widely on the details and sought views on whether the events in question had resulted in increased or decreased costs and the amount of any adjustment. Table 2.5 below shows the sums involved on the four occasions when IAEs have been requested by the SO and the final sums allowed by the Authority in each case.

Table 2.5[13] Summary of IAEs to date

£m	Net Income Adjustment Requested by NGET	Net Income Adjustment Allowed by the Authority
2002/03 Drax contract	5.34	5.34
2003/04 SSRT	5.54	5.54
2005/06 Scottish Constraint	30.18	25.85
2005/06 CAP047 (Frequency Response)	5.59	3.65

Form of the current incentive scheme

2.37. In March 2007, NGET consented to the Authority's proposals for an SO incentive scheme from 1 April 2007 to 31 March 2008. The current scheme includes

[13] All data in money of the day.

a 'deadband' of £15 million, ranging from £430 million to £445 million. In the event that outturn costs fall within this range, no payments are made through the incentive scheme. The parameters of the scheme are shown in Table 2.6.

Table 2.6 2007/08 SO incentive scheme

	IBC Target	Upside[14]		Downside[15]	
	£m	Sharing factor (%)	Cap (£m)	Sharing factor (%)	Floor (£m)
Final Proposal	430 - 445	20	10	20	-10

Transmission losses

2.38. The incentive on transmission losses operates by setting NGET a target for the volume of transmission losses. If NGET "beats" this target it receives a payment and if actual losses exceed the target it faces a cost. The calculation of this payment or cost is made by multiplying the difference between the actual and target losses by the TLRP, which to date has been set ex ante. For the current scheme the TLRP is set at 29£/MWh and the target volume is 5.95TWh.

Future incentive schemes

2.39. In the previous section of this chapter we considered the role and functions of the SO and the costs it incurs in undertaking these and discussed the historical and current SO incentive schemes. In this section we consider the development of future incentive schemes. In particular we look at the industry developments which may have a bearing on the nature of the future regime and the possible scope, form and duration of future incentive schemes. We also discuss whether the ability to raise Income Adjusting Events should be incorporated in future schemes.

Industry developments that may affect future System Operator costs

2.40. The costs incurred by the SO depend to a significant extent on the market conditions that prevail and on the way in which SO actions interact with the market arrangements. In Appendix 8, we provide a description of a number of industry developments that may affect supply and demand and that may, in turn, affect the costs incurred by the SO, these are summarised below:

- the EU Emissions Trading Scheme - which establishes a price for carbon emissions. This scheme is expected to result in additional generation costs which will be passed through to the wholesale price of power and on into Balancing Costs;

[14] Reward to NGET if costs are below target.
[15] Payment by NGET if costs are above target.

- the Large Combustion Plant Directive, LCPD - which places emission limits on large combustion plants. The LCPD may lead to a reduction in the output of existing coal plant with a consequential impact on market prices and on balancing costs;
- the planned increase in renewable generation (including offshore) - which, because it is likely to be located at the extremities of the transmission system, could lead to higher transmission losses and additional constraints together with the need to manage frequency and secure additional reserve. This will impact on SO costs;
- distributed generation which, as a result of being connected to the distribution network, may affect electricity flows and potentially impact on SO operations;
- offshore transmission - as outlined earlier, NGET has been appointed SO for UK offshore transmission networks. As offshore generation and transmission is developed it is likely that this will result in incremental costs to the SO for the development and implementation of additional commercial and operational arrangements;
- system access and constraint issues in Scotland - as discussed earlier, the costs of constraints in Scotland have been higher than expected since the implementation of BETTA. NGET has suggested that the incentives surrounding the management of network constraints could be better aligned;
- transmission access framework - the 2007 Energy White Paper announced a review led by Ofgem and the DTI to examine the arrangements through which new renewable generation can get access to the grid. Some of the changes being considered could impact on SO costs;
- modifications to the cash out arrangements - the cash out (or imbalance) arrangements are important in providing commercial incentives for market participants to balance their market positions. These arrangements are currently subject to industry review. Any changes to the cash out arrangements are likely to result in changes to the behaviour of market participants and therefore impact on SO balancing costs;
- frequency response - in recent years, frequency response costs have been one of the key components driving increases in balancing costs. The Balancing Services Standing Group are currently discussing potential changes to the Frequency Response Market. Any changes will have an impact on SO costs;
- transmission losses. Under the current BSC rules, the costs of transmission losses are recovered from generators and suppliers on a uniform basis. Four Modification Proposals (and two alternatives) have been raised to modify the BSC in relation to the treatment of transmission losses. The overriding principle of these modifications is to allocate transmission losses to BSC Parties on a 'zonal' basis. The Ofgem consultation on these arrangements closed on 31 July 2007 and it is the Authority's intention to publish its final decision by 20 September 2007. Any changes to introduce zonal losses will have an effect on the generating mix on the system at any one time, and is therefore likely to have an effect on the costs incurred by the SO.

Scope of future schemes

2.41. The scope of NGET's SO incentive scheme has remained unaltered since the implementation of NETA in April 2001. As part of this review we are considering whether the scope of the scheme should be amended. For example, as NGET is designate SO for UK offshore transmission networks, is it appropriate that the costs it incurs in this role should fall within its SO incentive scheme?

Form of future schemes

2.42. At present the electricity SO incentive is a single bundled scheme, this compares to the gas SO incentive which is broken down into a number of separate 'pots'.

2.43. The bundled approach in electricity has been considered appropriate in that it better aligns the interests of the SO with those of customers as the SO is incentivised to concentrate on reducing overall costs rather than maximising the profits it makes from the various different 'pots'. This may be a particularly relevant consideration in electricity where an action can serve several purposes so that there will always be some scope for interpretation when it comes to assigning costs to individual schemes. However, this approach reduces the transparency of the SO's actions.

Duration of future schemes

2.44. Ofgem has stated on a number of occasions that it believes it is appropriate for longer duration schemes to be implemented and that the duration of the SO incentive arrangements should become increasingly aligned with the transmission price control periods.

2.45. There is a clear trade-off between the flexibility of a one year incentive scheme, and the stability of a scheme of a longer duration. The greater flexibility of a one year scheme enables response to changing market conditions, whereas multi-year schemes would provide greater stability and allow trade-offs between investments and operating costs to be made.

2.46. Longer duration schemes would give the SO a clearer incentive framework under which to operate and would enhance its ability to consider investments that would only reduce costs over the course of several years. As a result, this approach would provide the SO with increased freedom and flexibility within which to carry out its role as SO and in doing so would be expected to reduce SO costs over time, to the benefit of customers.

2.47. However, longer duration schemes need to be able to reflect possible changes in market conditions over the period of the scheme, to ensure that the SO does not receive any windfall gains or make unreasonable losses. One possible way to achieve this is to consider the ways in which the SO's costs may be dependent upon certain output drivers. For example, as discussed in the following chapter, the gas shrinkage volume target is linked to the volume of gas flows through the St. Fergus gas terminals. For the electricity SO incentives, one possible output driver would be to link the volume of reserve purchased to the volume of wind generation connected to the system.

Interaction of electricity and gas SO costs and incentives

2.48. At present, the electricity and gas SO incentives are set essentially in isolation from one another. However, given the high level of gas-fired capacity on the electricity system, there are interactions between the two markets and the costs that the SOs face in balancing them. As part of this review, we would like to ensure that any interactions between the gas and electricity markets are addressed. A further consideration of this review is whether the incentive schemes should be more consistent.

Transparency and information provision

2.49. As part of its role as residual energy balancer the SO also has responsibility for ensuring the delivery of information to facilitate market efficiency. This responsibility spans information on its own actions as well as general market information and data. There are currently five main sources providing information on the GB electricity market, the Balancing Mechanism and System Operations. These sources are listed below and discussed in more detail in Appendix 9:

- the National Grid Balancing Services website is the main source of information on Balancing Services, NGET procurement and Code and Governance issues, excluding the BSC;
- the Balancing Mechanism Reporting System (BMRS) website (managed by Elexon[16]) provides near real time and historic Balancing data;
- the Elexon website provides key market data including BSC code modification;
- the System Operator Notification and Reporting System (SONAR) provides the market with SO and system related notifications in real time; and
- the National Grid Operational Forum provides regular opportunities for the SO and market participants to discuss the operation and performance of the power system regime.

2.50. Market participants have highlighted several areas of concern in relation to the provision of electricity information. These include:

- availability of certain data including historical data and wind generation forecasts
- integration, reliability and speed of reporting systems
- demand for data on how GB's demand is met (i.e. generation breakdown) and how much of GB's generation was being produced from embedded sources

[16] ELEXON is the Balancing and Settlement Code Company (BSCCo) established under the provisions of the BSC. The BSC contains the rules and governance arrangements for electricity balancing and settlement in Great Britain, and ELEXON is responsible for ensuring its proper, effective and efficient implementation. ELEXON is wholly owned but not controlled by NGET. ELEXON's independence of NGET is established by the BSC.

- preference for a single source for core electricity information as opposed to multiple sources

2.51. NGET is undertaking a consultation exercise aimed at understanding further industry's views on possible improvements in the area of electricity information provision.

2.52. Currently no element of the electricity SO incentive scheme is focussed on the provision and quality of information. This contrasts with the gas SO incentive scheme which contains a separate information incentive that targets NGG's performance in terms of its demand forecasting and the availability and the timeliness of certain gas market operational information provided on its website. In the electricity regime reliance is placed on the transmission licence and the Grid Code for provision of information.

3. System Operation in the Gas Market

Chapter Summary

This chapter provides details of the role of the SO in the gas market and how the SO is incentivised to undertake that role in an economic and efficient manner. We provide background to the current role of the SO and the tools available to it to fulfil that role. We also provide details of the historic costs incurred by the SO and discuss the industry developments that are likely to impact on those costs in the future. In the second part of this chapter we provide details of the incentive schemes that have been placed on the SO and how it has performed against these schemes. We then discuss the development of future SO incentive schemes.

Question 18: Are the current roles and functions of the SO appropriate, and do they ensure that the SO is able to operate the NTS in the most efficient and economic manner? If not, what changes would you recommend?

Question 19: In the electricity market the SO as residual balancer is able to contract ahead for various services. In the gas market the SO as residual balancer does not have the same ability. Do you consider that this difference is appropriate? Please explain your view.

Question 20: Do you consider that the costs incurred by the SO represent the costs that would have been incurred by an economic and efficient SO? Are there any particular areas where you consider that the SO has not incurred costs economically and efficiently? If so, please provide details of these areas and why you consider that to be the case.

Question 21: What are the key developments that will affect future System Operator costs? How will these developments impact on costs?

Question 22: Do you consider that the current form of the residual gas balancing incentives is appropriate? Please explain your reasoning.

Question 23: Do you believe that the existing linepack incentive has little impact on the behaviour of the gas SO? If so, do you have any suggested improvements for this aspect of the incentives?

Question 24: Is it still appropriate for the gas shrinkage volume target to be dependant on flows through St Fergus? If yes, please provide details of the relationship. If no, please explain your reasoning and provide your views on how the target should be set.

Question 25: Is the current gas cost reference price methodology still appropriate? If not, please explain what an appropriate methodology would be.

Question 26: Is the current form and scope of the gas system reserve incentive still appropriate (in terms of the volume and source of gas reserve bookings the SO considers necessary for the safe operation of the network, the contestability and locational nature of some of these requirements and the price at which it is efficient for these bookings to be made)? Do you consider that the sharing factors, cap and floor for this incentive are still appropriate? Please explain your views.

Question 27: We would welcome views on the indicative data provided by NGG on its requirements for gas reserve from April 2008, including views on its continued utilisation of LNG storage at the Isle of Grain importation facility.

Question 28: Would the increased stability of gas SO incentive schemes of longer duration be preferable to the increased flexibility offered by schemes of a shorter duration? Please provide your reasoning.

Question 29: Are there any aspects of the gas SO incentive schemes that you consider would be more effective if bundled, rather than remaining in their current form? Please provide details of how this may be achieved.

Question 30: Is it appropriate for participants (including the SO) to have the ability to raise Income Adjusting Events when unexpected events occur resulting in increased or decreased costs? If not, how could such cost uncertainties be addressed under an incentive scheme?

Question 31: Do you consider that it is appropriate that only the SO can propose modifications to the Statements that the SO is required to have in place under Special Condition C5 of its GT licence? Do you think that market participants should also be able to propose modifications to these Statements?

Introduction

3.1. This chapter provides details of the role of the SO in the gas market and how the SO is incentivised to undertake that role in an economic and efficient manner. Our discussion is structured in terms of:

- role of the SO - which describes the role and cost of the SO;
- SO incentive schemes - which sets out the experience of operating the incentive arrangements; and
- future incentive schemes - which considers the issues surrounding the design of future arrangements.

Role of the System Operator

3.2. The SO has a responsibility to ensure that the National Transmission System (NTS) remains within prescribed system pressure limits and that gas is transported from where it enters the NTS to where it is offtaken. There are two key aspects to the role of the SO in the management of the NTS:

- residual gas balancing - the commercial purchasing and selling of gas to keep the system in balance (on a daily basis) where the market is not able to balance energy flows into and out of the NTS; and
- gas system balancing - the physical management of the system using compressors and operating margins gas to maintain safe pressures on the system.

3.3. In Appendix 10, we also provide a description of the legislative and regulatory framework within which the gas SO operates. This is included for reference. However we would welcome any views that respondents have on whether this framework remains appropriate in the context of the issues addressed in this chapter.

Residual gas balancing

3.4. Under the Uniform Network Code (UNC), shippers have a commercial incentive to ensure that their inputs to, and offtakes from, the system are balanced on a daily basis (see Appendix 11). However, to the extent that shippers fail to balance their own positions, the SO has a responsibility to ensure that the system is balanced (residual balancing). The tools which the SO uses to perform its residual balancing role include trades on the on-the-day commodity market (OCM) and use of linepack - which refers to the volume of gas in the NTS.

3.5. Although trades on the OCM may be made by the SO in order to resolve locational constraints on the NTS, they are predominantly executed for energy balancing reasons (i.e. to address aggregate imbalances between demand and supply). Thus, in the event that the NTS is long or short of gas (in aggregate) over any given gas day, the SO can choose to buy or sell gas on the OCM. This may contribute directly to redressing the physical imbalance and it can also send signals to the market about the short or long position of the system as a whole, thus encouraging the market to resolve the imbalance itself.

3.6. The SO is able to manage the NTS linepack (within safe pressure limits). Because the SO has some discretion in deciding the extent to which linepack changes both within the gas day and between days, linepack is a key tool used by the SO in managing the NTS. Linepack can be used to respond to aggregate imbalances between demand and supply and can also be used for gas system balancing, see below.

Gas system balancing

3.7. In addition to the SO's role as the residual balancer, it also has a critical role in maintaining the safe operation of the NTS. This role entails ensuring that gas system pressures are maintained within safe operating limits across the network, and that gas is transported to the appropriate NTS offtake points. In its role as gas system balancer, the SO has a number of tools available to it. These include use of limited linepack flexibility, use of compressors and use of operating margins gas (gas reserve).

3.8. The gas SO is required to maintain system pressures across the NTS within safe operating limits. The SO has some flexibility in the way in which gas is managed across the gas day. This flexibility may be used by the SO both in its role as system balancer and residual balancer.

3.9. A key function of the SO is determining the optimal usage of compressors, which are critical for transporting gas across the network and maintaining pressures within safe operating limits. Compressor usage is dependant on the location at which gas enters the network. For example, if gas enters the NTS at points located a long way from demand (e.g. at St Fergus), relatively more compressor usage is required than if gas enters the NTS at points closer to demand (e.g. Bacton).

3.10. Under the terms of its Safety Case, NGG is required to have access to sufficient levels of gas reserve to maintain NTS system pressures in response to a variety of events (e.g. unexpected changes in demand, supply losses, loss of major supply infrastructure, pipe breaks, compressor failure, etc). A quantity of gas is also procured to manage the orderly rundown of the system following the declaration of a Gas Supply Emergency. These levels of gas reserve are normally described as operating margins (OM). The events that NGG needs to be able respond to can dictate how quickly this gas must be made available and where the gas should be stored. NGG assesses the OM requirement for each year and tenders for OM services on an annual basis. At present, the gas SO chooses to source the majority of OM through a combination of natural gas and LNG held in store.

Costs incurred by the System Operator

3.11. The costs incurred by the SO fall into two categories:

- **internal costs**, which relate to the day-to-day activities of the SO, and can be either operating costs or capital costs (such as staffing costs, the cost of operating control rooms and IT costs); and
- **external costs**, which are more directly linked to the SO activities set out earlier in this chapter, such as the costs incurred by the SO in fulfilling its role as residual balancer.

3.12. An assessment of the level and nature of internal SO costs over the period 2007 - 2012 was recently conducted under the Transmission Price Control Review (TPCR) and, as a consequence, internal costs do not fall within the scope of this review[17]. However, external costs were only assessed up to April 2008 (through the specification of the gas SO incentive scheme). For this reason, the remainder of this chapter focuses on **external** costs incurred by the SO. The key components of external costs potentially incurred by the SO in the operation of the network relate to shrinkage, use of operating margins (gas reserve) and trades on the OCM.

[17] In addition, Xoserve costs for NTS are being dealt with through the Gas Distribution Price Control Review.

Shrinkage

3.13. The most significant category of external SO cost is the cost of shrinkage. NTS shrinkage arises due to measured own use gas (e.g. incurred in the operation of compressors used to transport gas around the NTS), unbilled energy (the difference between actual measured Calorific Value of gas entering the NTS, and Calorific Value at which this energy is billed) and meter error. The amount of NTS shrinkage over time is the difference between NTS entry and exit allocations.

3.14. The actual shrinkage cost incurred by NGG over the period April 2006 - April 2007 is set out in Table 3.1 below. The table summarises the costs of each of the components of shrinkage, including:

Table 3.1: Actual cost of shrinkage 2006/07

DESCRIPTION	**COSTS £m**
Own Use Gas	98.06
Unbilled Energy (Calorific Value Shrinkage)	0.35
Unaccounted For Gas (excluding meters reconciliation)	16.88
Meter Reconciliation Adjustments (primarily Farningham £11.5m[18])	(12.09)
Electric Compressor	0.52
TOTAL	**103.72**

Use of operating margins

3.15. The costs associated with OM gas can mainly be divided into storage capacity costs and commodity (gas) costs. Storage capacity costs are incurred through the booking of space in gas storage facilities with commodity costs only being incurred when OM gas is utilised. Additional costs are also incurred through changes in annual bookings of OM (termed reprofiling costs), and usage costs.

3.16. The SO is incentivised to reduce storage, reprofiling and usage costs, being fully exposed to any outturn which is under / over the agreed yearly target[19].The following table outlines the incentive costs incurred in using OM gas in the last few years:

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[18] In August 2006, NGG announced that they had identified at Farningham an offtake meter error. This finding triggered the reallocation of funds relating to Non Daily Metered Small Supply Points (NDM SSP) through the UNC reconciliation process.
[19] The SO recovers the cost of the volume of commodity used through balancing neutrality charges.

Table 3.2: Actual cost of OM 2004/05 - 2006/07

Year	Total OM costs (excl. gas costs) [20]	Storage capacity booked
04/05	£16,332,006	1771 GWh
05/06	£16,561,498	1540 GWh
06/07	£19,852,017	1650 GWh

Trades on the OCM

3.17. Significant costs may be incurred by the SO in balancing the system through the buying and selling of gas through the OCM. Table 3.3 illustrates the annual cost of buy and sell trades by the SO on the OCM over the period 2002 - 2007.

Table 3.3: Actual cost of trades on the OCM undertaken by the SO (2002 - 2007)

Year	Buy			Total Buy (£M)	Sell			Total Sell (£M)
	NBP Title	NBP Locational	NBP Physical		NBP Title	NBP Locational	NBP Physical	
2002/03	90%	10%	0.08%	**24**	85%	15%	0.06%	**34**
2003/04	87%	13%	0.00%	**23**	100%	0%	0.00%	**20**
2004/05	100%	0%	0.00%	**18**	100%	0%	0.00%	**26**
2005/06	100%	0%	0.00%	**24**	100%	0%	0.00%	**68**
2006/07	93%	7%	0.00%	**28**	91%	9%	0.00%	**38**

3.18. As in electricity, the cash out arrangements are not used to recover the costs that the SO incurs in balancing the system. Instead, the money that is paid to (or paid by) the SO as a result of imbalance charges, scheduling charges and purchases and sales of gas on the OCM is returned to (or paid by) shippers via the balancing neutrality charge. The aggregate system payments are returned to (or paid by) shippers on the basis of their throughputs (the sum of their inputs and outputs).

System Operator Incentive Schemes

3.19. As outlined in Chapter 2 in the context of electricity, the key objective of an SO incentive scheme is to place commercial incentives on the SO to manage the costs of system operation as efficiently as possible in order to reduce the overall cost to the consumer. The underlying principle of the current incentive schemes is that, if the actual costs of system operation turn out to be below those that would have been expected from an efficient SO, then both the SO and customers share a proportion of those savings. However, if costs outturn above expected levels, then these higher costs are also shared between the SO and customers.

[20] Includes all storage, usage and reprofiling costs.

3.20. The extent of risk sharing between the SO and customers is determined by the level of upside and downside sharing factors. Caps and floors then set upper and lower bounds on the risk that is faced by the SO. Customers bear the full benefit (cost) if the cap (floor) on incentive payments is reached. As outlined in Chapter 1, a key consideration for this review is an assessment of the current overall risk / reward balance between the SO and customers, and whether this balance remains appropriate going forward.

3.21. Unlike in electricity, the gas SO faces a number of separate external incentive schemes, each designed to address a specific category of external cost. The gas SO incentives are therefore "unbundled" as opposed to the "bundled" form of the electricity SO incentives. The current gas SO incentives cover three main areas:

- **residual gas balancing** covering the price at which NGG takes residual balancing actions and the stability of the linepack within the NTS;
- **system balancing incentives** that target the cost of gas lost due to shrinkage (i.e. losses) and held in storage by NGG to provide system gas reserve; and
- **information incentives** that target NGG's performance in terms the accuracy of its demand forecasting and the availability and timeliness of gas market operational data.

3.22. An overview of each of the current incentive schemes is provided below. The current incentive schemes have been defined up to 1 April 2008, recognising that there were a number of significant issues that needed to be addressed before any longer duration could be considered.

Residual gas balancing

3.23. As outlined above, in its role as residual gas balancer, the SO faces a choice as to whether to address aggregate daily system imbalances through buy/sell actions on the OCM, or whether to allow this imbalance to be met through system linepack[21]. To reflect this trade-off, the SO's residual gas balancing incentive comprises two main components. These are:

- a **price** incentive that gives the SO an incentive to maintain the price of the gas it buys or sells for residual balancing reasons as close to the market price as possible; and
- a **linepack** incentive that gives the SO an incentive to minimise changes in levels of end of day linepack.

3.24. The residual balancing incentive is therefore calculated on a daily basis, with the daily revenue/cost to the SO calculated as being the sum of the incentive payment received under both the price and linepack components of the incentive.

[21] Assuming resulting levels of linepack are within safe operational levels.

3.25. The price element of the incentive arrangement is designed to give the SO a commercial incentive to action gas balancing trades at strike prices that are as close as possible to the system average price (SAP) on the OCM. Under this scheme, the SO is incentivised to minimise the daily residual balancing Price Performance Measure (PPM).

3.26. The PPM is calculated daily from the spread between the highest and lowest prices traded by the SO when performing eligible balancing actions on the OCM. This spread is expressed as a percentage of the System Average Price (SAP). If the PPM is less than 10 percent then the SO makes a profit and if it is greater than this the SO makes a loss. NGG's potential daily profit is capped at £5,000 and its daily loss cannot be higher than £30,000. The daily price incentive and NGG's performance under this incentive can be seen in Figure 3.1 and 3.2 respectively.

Figure 3.1: Daily price incentive

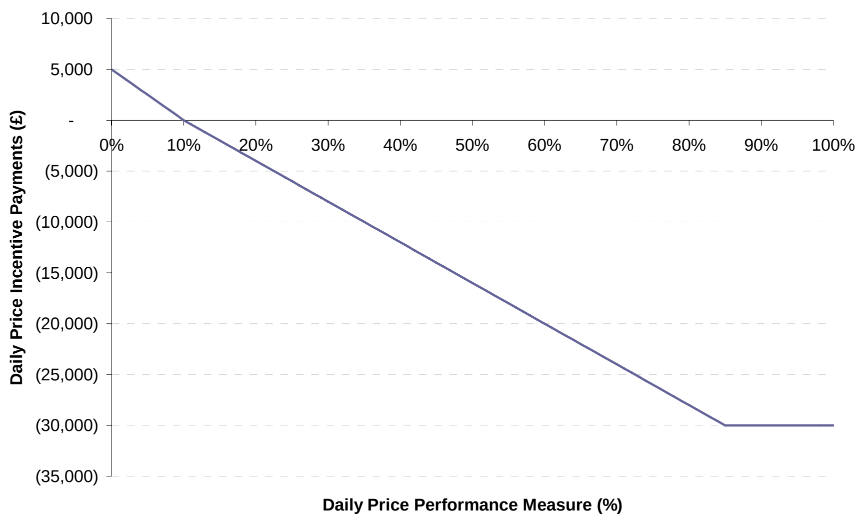
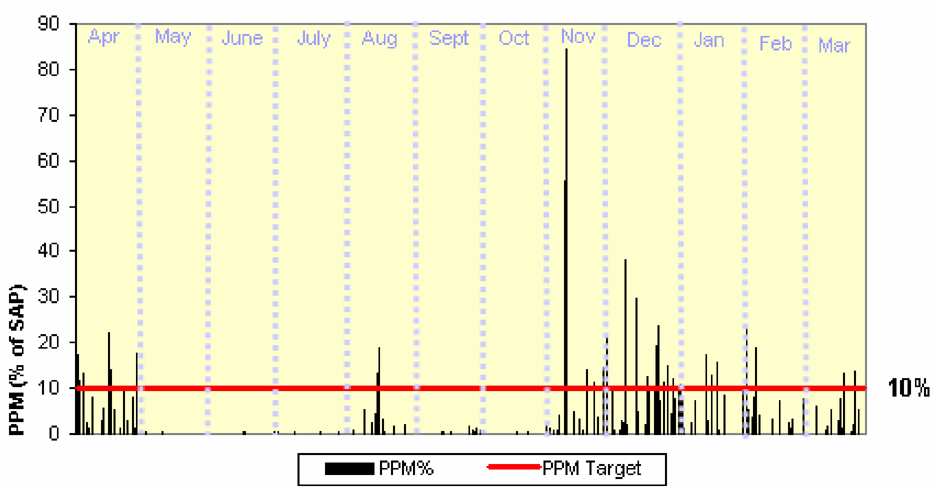


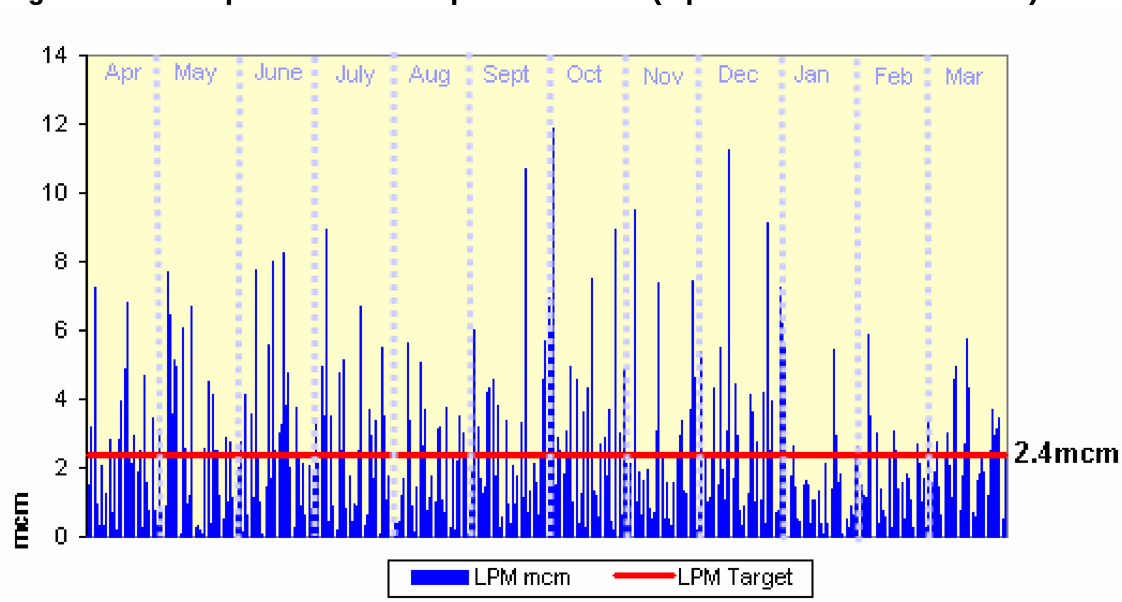
Figure 3.2: Price incentive performance (April 2006 - March 2007)



3.27. In 2006/07, NGG was within 10 percent of PPM (and therefore made profits under the scheme) on 94 percent of days. This compares to 87 percent of days in 2005/06. In addition, NGG has achieved the maximum gains (PPM= zero percent) on more than one third of occasions (PPM will be zero percent on occasions when NGG takes no balancing actions because the difference between the maximum and minimum price defaults to zero.)

3.28. The linepack element of the incentive arrangement is designed to give the SO a commercial incentive to reduce significant changes in end-of-day linepack. It is based on a similar structure to the price performance incentive, having the same daily cap and floor. In this instance, NGG's performance is measured by the Linepack Performance Measure (LPM), which is calculated as being the absolute value of the change in linepack (in mcm) between the start and close of each gas day. If the change in linepack is less than 2.4 mcm, then NGG receives a payment, conversely if the change is greater than this, NGG has to make a payment. NGG's daily linepack incentive performance over the last formula year is set out below.

Figure 3.3 Linepack incentive performance (April 2006 - March 2007)



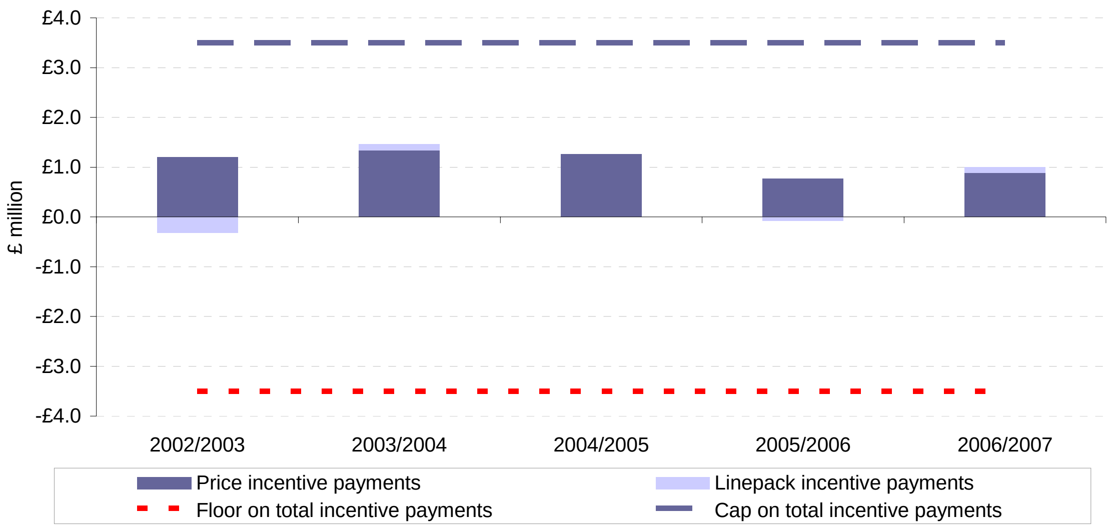
3.29. End-of-day linepack movements were 2.4mcm or less on only 60% of days in 2006/07 (therefore triggering an incentive payment). In addition, since 2002, NGG has never received the maximum potential daily incentive payment (that would be paid if end-of-day linepack levels remained constant). Overall, NGG's performance under this incentive has not varied significantly during the past few years, a fact that might imply that management of linepack may be driven by operational requirements (as opposed to responding to financial incentives).

Overall residual balancing incentive performance

3.30. The incentive payments related to each component of the residual balancing incentive are initially calculated on a daily basis with a £5k cap and -£30k floor for each incentive. However, at the end of a year, both sets of daily incentive payments are combined into an annual total, which is subject to an annual cap of £3.5m and a floor of -£3.5m.

3.31. Figure 3.4 shows the payments under both incentive schemes including the cap and floor on total residual balancing incentive payments since 2002. Over the past five years, incentive payments have remained well within the cap and floor and the majority of residual balancing incentive payments are due to the price incentive.

Figure 3.4: Annual residual gas balancing incentive payments, cap and floor, 2002/03-2006/07[22]



3.32. The two residual balancing incentive schemes were originally designed to operate jointly, recognising the interaction between trades on the OCM and management of linepack for residual gas balancing purposes. However, as noted above, NGG's actions appear to be focused on the price incentive, with the linepack incentive having little effect on SO behaviour.

[22] Please note that the figures for 2006/07 are indicative only and are subject to an independent audit review.

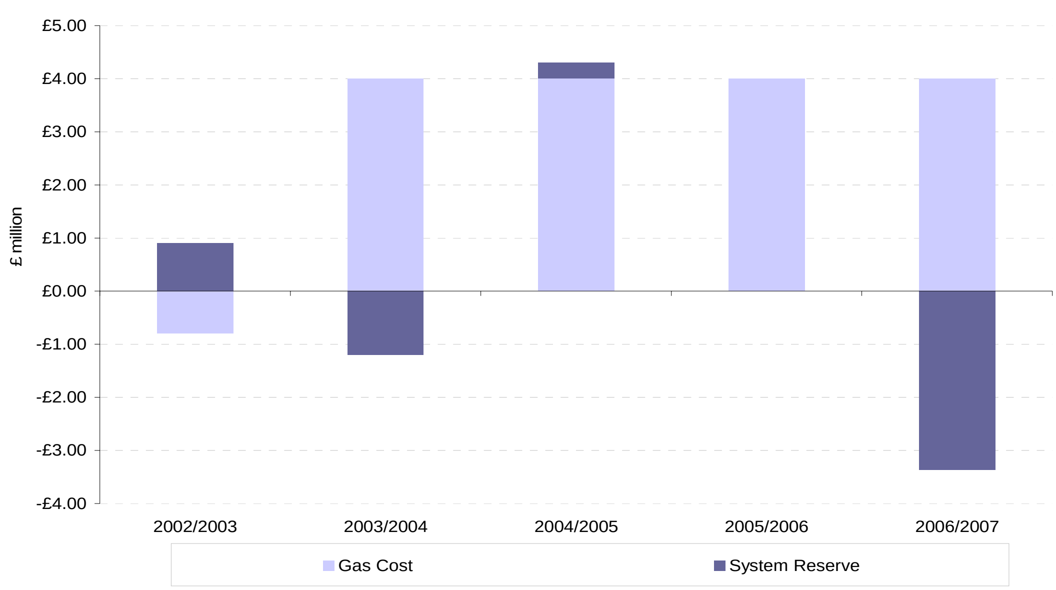
System balancing incentives

3.33. There are two components to the system balancing incentive payments. These are:

- a gas cost incentive (that targets the cost of gas attributed to shrinkage, including gas used in compressors and for other operational purposes, as well as the cost of operating electric NTS compressors); and
- a system reserve incentive (that targets costs incurred by the SO in booking or using gas in store for the purposes of satisfying operating margins requirements).

3.34. NGG's system balancing incentive performance since 2002/03 is illustrated in Figure 3.5 below together with estimates for the performance in 2006/7.

Figure 3.5: Annual system balancing incentive payments, 2002/03 - 2006/07



Gas cost incentive

3.35. The SO uses compressors located around the NTS, to ensure that the system integrity is maintained, and pressures are kept within safe operating margins. The majority of these compressors are gas fuelled at present.[23] In 2006/07, the volume

[23] We note, however, that the SO is currently implementing a programme to install gas compressors driven by Variable Speed electric Drives (VSD), replacing some of the conventional gas-fuelled turbine drivers. This is driven by the need to comply with emissions

of gas used by gas fuelled compressors on the NTS was 5266 GWh[24]. It is this own use gas that represents the most significant component of the gas cost incentive.

3.36. The gas cost incentive has also comprised two additional elements (that result from NTS metering uncertainty and Gas (Calculation of Thermal Energy) Regulations requirements). These are unaccounted for gas (essentially the difference between measured NTS entry volumes and NTS offtake volumes) and unbilled energy or, Calorifc Value (CV) shrinkage (which is the difference between the actual measured CV of gas entering the NTS and the CV at which this energy is billed).

3.37. Under the 2006/07 incentive scheme, NGG had an annual gas cost target set at £184.4m. This was calculated as being a gas cost reference price (GCRP) applied to a specified target volume. £0.5m was included in this for the operation of electric compressors. In this scheme NGG receives incentive payments where actual costs are below target (subject to a cap of £4million), and makes incentive payments where actual costs are above target (subject to a payment limit of £3million). The two components of the gas cost incentive (volume and reference price) are described in more detail in the following sections.

Volume of Gas Shrinkage

3.38. In developing the SO incentive scheme for 2007/08, it was apparent that a key driver of the volume of gas shrinkage on the NTS was the pattern of flows across the network - and more specifically the proportion of gas that is delivered through the St Fergus entry terminal[25]. As the SO has no control over the volume of St Fergus flows, we concluded that it was appropriate for the gas cost volume target to vary with the levels of actual flows through the St Fergus terminal. We therefore specified high, medium and low targets for gas shrinkage volumes, based on actual average flows through the St Fergus terminal over 2007/08[26].

3.39. In the future, the gas shrinkage incentive will also need to take into consideration the extent and timing of the replacement of existing gas fuelled compressors by electric driven compressors. This will be especially relevant given that the first of these compressors is expected to be operational by 2008/09.

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legislation and will increase overall efficiency of the compression process. The first electric drive units are expected to be commissioned during 2008/9.

[24] This represents 0.48% of NTS throughput in 2006/07.

[25] Levels of own use gas (through compressor usage) are strongly positively related to the volume of flows through St Fergus, as gas entering through this terminal typically needs to be transported a greater distance across the NTS.

[26] The high volume target for 2007/08 is 8,312 GWh (if average flows through St Fergus exceed 100 mcm/day), and the low target is 6,393 GWh (if average flows through St Fergus are below 85 mcm/day).

Pricing of Shrinkage Gas

3.40. The gas cost scheme utilises a forward looking gas price, the GCRP. Since 2004/05, the GCRP is calculated from the average of the prices of quarterly forward prices from the previous year, volume weighted by total shipper net flows into the NTS from beach and storage terminals (net of injections) from two years previously.

3.41. This approach represented a change from previous years, in which the GCRP was calculated using a relatively narrow window of averaging (over period 1 March to 20 March of the formula year immediately prior to the year to which the GCRP would apply). It was considered this approach would avoid the need for NGG to source large volumes of gas over a short time period to hedge the price risk associated with shrinkage gas.

3.42. An alternative approach to the current arrangements would be to define a fixed price ahead of each formula year (or number of formula years). This would have benefits in terms of simplicity, however would place price risk on NGG (especially if specified for more than one formula year). A second alternative would be to use a forward reference price that changes through the year, such as on a monthly or quarterly basis. This could be achieved through indexing each month's (or quarter's) reference price to forward prices for a specified period ahead[27]. A third alternative would be to set a reference price based on day-ahead prices, in line with one of the options we are considering in the forthcoming Gas Distribution Price Control.

Historical performance of Gas Cost Incentive

3.43. As Table 3.4 shows, NGG has received maximum incentive payments for the past four years. It is clear from this table that NGG has performed well against this incentive, receiving incentive payments in line with the incentive cap.

Table 3.4 – Annual gas cost incentive payments, NGG share

Year	GCRP (p/kWh)	Target (£ million)	Costs (£ million)	Incentive payment (£ million)
2003/04	0.7	61.9	44.4	4.0
2004/05	0.9	82.6	59.7	4.0
2005/06	1.3	112.7	91.4	4.0
2006/07	2.0	184.4	115.8[28]	4.0

[27] For example, following a methodology in which a monthly index price is based on three-month ahead forward prices, the reference price for July for the year in question would be calculated as a weighted average of all forward trades for July contracts during April of the same year.
[28] This figure does not reflect the reconciliation following the adjustment of the Farningham offtake meter error (see table 3.2 above). The incentive payment would be the same under either cost figure (£4million cap).

System reserve incentive

3.44. As noted above, the SO is required to have access to sufficient levels of gas reserve (typically held as gas in store) to maintain NTS system pressures in response to a variety of events (e.g. unexpected changes in demand, supply losses, loss of major supply infrastructure, pipe breaks, compressor failure).

3.45. The system reserve incentive specifies a target cost for the booking of gas reserve requirements (although the cost of buying and selling gas in storage are not included, instead being met through UNC arrangements)[29]. Caps and floors have not been specified for this incentive in the past, and sharing factors have been set at 100%. This was due to difficulties in attaining full contestability in the provision of system reserve (NGG procures a large proportion of its reserve services from National Grid LNG facilities). In 2006/07, the target cost for the gas reserve incentive was set at £16.6m. NGG's actual cost significantly exceeded the incentive target, and NGG was therefore required by the incentive regime to make a payment of over £3 million.

3.46. In developing the gas reserve incentive for 2007/08, NGG specified that it had both locational and non-locational requirements for gas reserve at storage facilities across the NTS. These bookings were required at a combination of LNG storage facilities (including some bookings at the Isle of Grain LNG importation facility) and at natural gas storage facilities. Typically, the locational gas reserve requirements specified by NGG (particularly at the Isle of Grain facility) were significantly more expensive than bookings of gas reserve held at other locations. In our Final Proposals consultation document, we noted that NGG's requirements for gas reserve would form an important part of our review of the SO incentives.

3.47. For the purposes of supporting this consultation and to give some context to the issues outlined, NGG has presented data on how future supply patterns could affect estimates for gas reserve across the NTS which is included in Appendix 15. NGG has stated that this information is based on the output from NGG's 2006 "Transporting Britain's Energy" (TBE) consultation process. This is currently being updated using the latest information gathered from the 2007 TBE process and will therefore be revised at a later stage. Over the coming months we will be undertaking analysis to understand NGG's requirements in more detail, and specifically whether:

- stated requirements at (relatively expensive) locational LNG storage facilities are justified; and
- whether substitutable source for gas reserve at these locations have been fully explored.

3.48. We will also be working with NGG to understand progress it has made towards its objective of purchasing reserve services from independent third party providers

[29] Specifically, through balancing neutrality.

over the course of the current price control period (i.e. until April 2012). We will include initial conclusions from this analysis in our Initial Proposals consultation.

Quality of information incentives

3.49. The Gas SO has an important role in providing timely and accurate market information. Gas SO information incentives were implemented from October 2006 in response to customer requests to improve two specific aspects of gas SO activities. These related to the accuracy of NGG's day-ahead gas demand forecasts and the performance of NGG's website (specifically the availability and timely provision of key gas operational data).

Demand forecasting incentive

3.50. The form of the demand forecasting incentive was designed to give a financial reward for increases in accuracy of the SO's demand forecasts. Increases and falls in accuracy are measured in percentage terms as compared to a defined 2005/06 benchmark performance. A set target of a 5 percent improvement in accuracy would imply a payment to NGG of £1.6m (with further reward available at higher improvement rates). Penalised falls in accuracy were curbed at 5 percent (which would have resulted in an incentive payment by NGG of £1.6m).

3.51. Over this whole period NGG achieved a 30 per cent improvement on the 2005/06 benchmark performance. This significantly exceeded target levels and resulted in an incentive payment to NGG of around £3m.

Website performance incentives

3.52. The website performance incentives were also implemented from 1 October 2006, and were specified to deliver improvements in the timeliness and availability of a selection of key gas market operational data[30].

3.53. Over the period 1 October 2006 to 1 April 2007, NGG's monitored timeliness under this incentive significantly exceeded the benchmark specified for the period (performance was improved by 93 per cent over the 2005/06 benchmark performance, the target improvement being set at 51.5% in the original incentive). On the contrary, performance in terms of website availability fell below the set 2005/06 performance benchmark.

3.54. The overall website incentive performance measure is calculated as the average improvement in website performance (i.e. of both the availability and

[30] These data were selected after extensive consultation, and are: linepack data, physical flows into the NTS, nominated flows into the NTS; and forecast demand.

timeliness components). As the performance of each component is bottomed at zero, the overall improvement in the website performance measure was nearly 50% in the period to 1 April 2007[31] (representing an incentive payment to NGG just over £1.1m).

Future developments

3.55. As the quality of information incentives had only been in place for a relatively short period of time prior to the publication of Final Proposals for the 2007/08, we retained these incentives for the current formula year. However, the nominal value of the incentives was retained (effectively halving the annual value of the incentives), and the benchmarks for each incentive amended to reflect both performance over winter 2006/07 and the fact that these incentives will cover summer as well as winter periods[32].

3.56. Overall, we consider that these incentives have been effective in delivering real improvements in the accuracy of day-ahead gas demand forecasts and the performance of the SO's website. Beyond the current formula year, however, we consider there to be three potential ways forward. These are:

- retain the existing quality of information incentives with updated parameters, which would require a review of the level of incentive payments and the benchmark performance levels;
- remove one or more of the incentives completely and monitor performance on an ongoing basis; and
- introduce an alternative quality of service regime, potentially including standard of performance obligations on NGG. Such a set of arrangements could be defined to be consistent with the arrangements in place to ensure certain specified quality of service standards are met by Distribution Network Operators (DNOs). More details on these standards are included in Appendix 12.

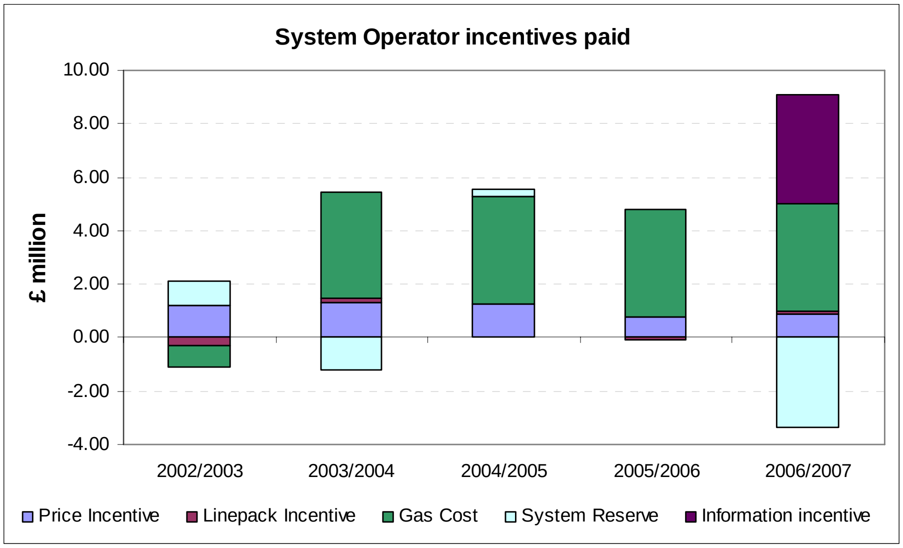
3.57. In part, the choice between these different approaches will depend on whether customers consider that further improvements to the service provided by NGG are required.

Summary of NGG's historical performance

3.58. Figure 3.6 illustrates NGG's performance over the past years under each incentive schemes that are currently in place for the gas SO.

[31] The overall measure is calculated as a simple average of the 93% improvement in timeliness and the 0% improvement in availability.
[32] For further details, see National Grid Gas System Operator Incentives from 1 April 2007, March 2007, Ofgem, 43/07.

Figure 3.6: Annual incentive NGG share and payments under currently existing incentive schemes



Future incentive schemes

3.59. In addition to specific issues relating to the existing gas SO incentive schemes discussed above, there are a number of more generic issues that need to be considered in the development of future incentive schemes. These include: duration of any potential scheme, extent of unbundling and Income Adjusting Event (IAE) provisions.

Duration

3.60. At present the (external) gas SO incentive schemes are specified for the year through to April 2008. However, as outlined in Chapter 2, while recognising that there is a trade-off between the greater flexibility that a one year scheme offers (in terms of responding to changing market conditions), in principle we favour schemes that extend for a number of years as these provide greater stability and enable the SO to make trade-offs between investment and operating costs.

3.61. When considering the merits of a change to the duration of the scheme it will be important to consider the impact that industry developments may have on future SO costs. The level of costs incurred by the gas SO in fulfilling its roles and responsibilities is necessarily affected by a range of factors, many of which are outside of the SO's direct (or indirect) control. As in electricity, we have identified some factors that could have an impact on the role and functions of the gas SO. These developments and their implications for SO activity are explained in Appendix 13. These include changes to:

- the pattern of gas flows across the NTS - these are likely to change significantly with the decline in gas supplies from the UK Continental Shelf. These changes are likely to have significant implications for the way in which the SO operates the network;
- recent enhancements in the provision of information by the SO and / or market participants - by providing more timely and accurate market information, these enhancements might be expected to reduce the volume of activity that the SO needs to undertake;
- the development of a contestable market for Operating Margins - this could allow the SO to purchase OM at lower prices than at present; and
- industry arrangements - the industry arrangements within which the SO operates are of key importance to the nature and volume of activity that the SO is required to undertake. The ongoing review of electricity cash out arrangements (discussed in Chapter 2) may have implications for gas SO costs.

Extent of unbundling

3.62. The current gas SO incentive is specified as a number of unbundled schemes. This contrasts with the electricity scheme that is "bundled" into a single incentive. The unbundled approach in gas has developed over time, largely in response to a perceived need to target the schemes to influence specific SO actions (e.g. activities in the OCM), or deliver improvements in specific services (e.g. the quality of information incentives). However, in principle we consider there are benefits from adopting a more bundled approach to incentive schemes (such as enabling the SO to focus on overall cost levels, rather than on maximising returns from a range of more specific schemes).

IAEs

As discussed in Chapter 2, we accept that the provision for IAEs may be required under certain conditions (such as in response to force majeure and/or security events). However, we also note that, in the context of consultations on previous IAEs, market participants have raised concerns that the current IAE provisions allow the SO to appeal some elements of cost whilst retaining benefits arising from other areas of the scheme. In addition, some market participants have expressed concerns that a lack of transparency may make the effective assessment of proposed IAEs difficult.

Appendices

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 and which are replicated below.

1.3. Responses should be received by **28 September 2007** and should be sent to:

Philip Davies
Director, GB Markets
Ofgem
9 Millbank
London
SW1P 3GE

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. Any questions on this document should, in the first instance, be directed to Lisa Martin (020 7901 7123) or in relation to gas matters, Vanja Munerati (020 7901 7070). Email gb.markets@ofgem.gov.uk.

CHAPTER: One

There are no specific questions in this chapter

CHAPTER: Two

Question 1: Do the current roles and functions of the SO ensure that the SO is able to operate the electricity transmission system in the most efficient and economic manner? If not, what changes do you consider should be made to the roles and functions of the SO such that it is better able to operate the electricity transmission system in the most efficient and economic manner?

Question 2: Do you consider that it is appropriate that only the SO can propose modifications to the Statements that the SO is required to have in place under C16 of its transmission licence? Do you think that market participants should also be able to propose modifications to these Statements and should they sit elsewhere, for example in the BSC?

Question 3: Do you consider that the costs incurred by NGET in its role as electricity SO represent the costs that would have been incurred by an economic and efficient SO? Are there particular areas where you consider that NGET has not incurred costs economically and efficiently? If so, please provide details.

Question 4: Do you agree that through BSUoS is the most appropriate way to recover the costs incurred by the SO? If not, please provide details of how these costs should be recovered.

Question 5: Do you consider that previous SO incentive schemes have been effective in ensuring that NGET as SO has operated the electricity system in an efficient and economic manner and managed the external costs of operating the system effectively? To what extent was the increased level of system operation costs incurred by the SO in 2006/07 attributable to the absence of an incentive scheme for that period? Please provide details of any areas where you consider that the SO incentive schemes have not been effective.

Question 6: Do you consider that a sliding scale scheme is the most appropriate way for an SO incentive scheme to operate? If not, please indicate what you consider to be a more appropriate type of scheme.

Question 7: Do you consider the use of the Net Imbalance Adjustment to be an appropriate way of adjusting for the costs resulting from market participants' actions that the SO has little control over? If not, how could this adjustment be improved?

Question 8: Is it appropriate for participants (including the SO) to have the ability to raise Income Adjusting Events when unexpected events occur resulting in increased or decreased costs? If not, how could such cost uncertainties be addressed under an incentive scheme?

Question 9: Do you consider that the costs of operating offshore networks should be included in the SO incentive scheme? Are there any other additional elements that you consider should be included? Are there elements that are currently included in the scheme which should be removed?

Question 10: Do you think it is appropriate to consider unbundling the electricity SO incentive scheme? If so, which areas do you consider should be separated out and how might the SO be incentivised in these circumstances?

Question 11: Would longer term SO incentive schemes provide greater opportunities for investment that ought over the longer term to result in greater net efficiencies in SO costs?

Question 12: If we were to consider a longer term SO incentive schemes, what are the key drivers of SO costs that would need to be considered over the longer period? In what way could these drivers be captured in the incentive scheme?

Question 13: What are the key developments that will affect future System Operator costs? How will these developments impact on costs?

Question 14: Are there areas in which the current transmission losses incentive scheme could be enhanced to improve further the incentives on the SO to operate the electricity transmission system in an efficient and economic manner?

Question 15: What additional market information do you consider should be made available to the market by the System Operator, and vice versa? Please explain how this information would improve system operation and market efficiency?

Question 16: Is there sufficient transparency surrounding the SO incentives both in terms of the process for setting the incentive parameters and in terms of the information on costs provided by NGET? If not, what additional information do you consider should be made available?

Question 17: Do you consider it appropriate that the electricity SO should have quality of information incentives placed on it (as is the case with the gas SO)? If so, how should the SO be incentivised?

CHAPTER: Three

Question 18: Are the current roles and functions of the SO appropriate, and do they ensure that the SO is able to operate the NTS in the most efficient and economic manner? If not, what changes would you recommend?

Question 19: In the electricity market the SO as residual balancer is able to contract ahead for various services. In the gas market the SO as residual balancer does not have the same ability. Do you consider that this difference is appropriate? Please explain your view.

Question 20: Do you consider that the costs incurred by the SO represent the costs that would have been incurred by an economic and efficient SO? Are there any particular areas where you consider that the SO has not incurred costs economically and efficiently? If so, please provide details of these areas and why you consider that to be the case.

Question 21: What are the key developments that will affect future System Operator costs? How will these developments impact on costs?

Question 22: Do you consider that the current form of the residual gas balancing incentives is appropriate? Please explain your reasoning.

Question 23: Do you believe that the existing linepack incentive has little impact on the behaviour of the gas SO? If so, do you have any suggested improvements for this aspect of the incentives?

Question 24: Is it still appropriate for the gas shrinkage volume target to be dependant on flows through St Fergus? If yes, please provide details of the relationship. If no, please explain your reasoning and provide your views on how the target should be set.

Question 25: Is the current gas cost reference price methodology still appropriate? If not, please explain what an appropriate methodology would be.

Question 26: Is the current form and scope of the gas system reserve incentive still appropriate (in terms of the volume and source of gas reserve bookings the SO considers necessary for the safe operation of the network, the contestability and locational nature of some of these requirements and the price at which it is efficient for these bookings to be made)? Do you consider that the sharing factors, cap and floor for this incentive are still appropriate? Please explain your views.

Question 27: We would welcome views on the indicative data provided by NGG on its requirements for gas reserve from April 2008, including views on its continued utilisation of LNG storage at the Isle of Grain importation facility.

Question 28: Would the increased stability of gas SO incentive schemes of longer duration be preferable to the increased flexibility offered by schemes of a shorter duration? Please provide your reasoning.

Question 29: Are there any aspects of the gas SO incentive schemes that you consider would be more effective if bundled, rather than remaining in their current form? Please provide details of how this may be achieved.

Question 30: Is it appropriate for participants (including the SO) to have the ability to raise Income Adjusting Events when unexpected events occur resulting in increased or decreased costs? If not, how could such cost uncertainties be addressed under an incentive scheme?

Question 31: Do you consider that it is appropriate that only the SO can propose modifications to the Statements that the SO is required to have in place under Special Condition C5 of its GT licence? Do you think that market participants should also be able to propose modifications to these Statements?

Appendix 2 – The Authority's Powers and Duties

1.7. 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).

1.8. 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.[33]

1.9. 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[34].

1.10. 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.

1.11. 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[35]; and
- The interests of individuals who are disabled or chronically sick, of pensionable age, with low incomes, or residing in rural areas.[36]

[33] entitled "Gas Supply" and "Electricity Supply" respectively.
[34] 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.
[35] 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.
[36] The Authority may have regard to other descriptions of consumers.

1.12. 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[37] 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.

1.13. 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.

1.14. 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[38] 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.

[37] or persons authorised by exemptions to carry on any activity.
[38] Council Regulation (EC) 1/2003

Appendix 3 - Glossary

A

Ancillary Services

These are mandatory, necessary or commercial services used by the Electricity System Operator to manage the system and to meet their license obligations.

B

Balancing and Settlement Code (BSC)

This sets out the rules for governing the operation of the Balancing Mechanism and the Imbalance Settlement process and also sets out the relationships and responsibilities of all electricity market participants.

Balancing Mechanism (BM)

This is the mechanism by which the electricity System Operator procures commercial services (Balancing Services) from generators and suppliers post gate closure, in accordance with the relevant provisions of the Balancing and Settlement Code (BSC) and the Grid Code.

Balancing Services

The services that electricity System Operator needs to procure in order to balance the transmission system.

Balancing Services Use of System charges (BSUoS)

This is the daily charge, levied by the System Operator on users of the transmission system, in order to recover the costs of operating the transmission system and procuring and utilising Balancing Services.

Black Start

This is the ability to start a generating plant without external power supplies. This service is typically provided by Medium speed diesel engines and small OCGTs.

C

Calorific Value (CV)

The ratio of energy to volume measured in Megajoules per cubic meter (MJ/m3) which for a gas is measured and expressed under standard conditions of temperature and pressure.

Cash out arrangements (in electricity)

The arrangements whereby generators and suppliers pay or are paid for imbalances (shortages and surpluses of power relative to their contracted commitments)

Compressor Station

An installation on the National Transmission System (NTS) that uses gas turbine or electricity driven compressors to boost pressures in the pipeline system; it is used to increase transmission capacity and move gas through the System.

Connection and Use of System Code (CUSC)

Connection and Use of System Code (CUSC) constitutes the contractual framework for connection to, and use of, National Grid's high voltage transmission system.

D

Distribution Network (DN)

An administrative unit responsible for the operation and maintenance of the local pipeline network within a defined geographical boundary.

Distribution System

A network of mains operating at three pressure tiers: intermediate (2 to 7barg), medium (5mbar to 2barg) and low (less than 75mbarg).

F

Fast Reserve

This is the fast provision of reliable power via increased generation or reduction in demand which can be provided within 2 minutes, at a delivery rate of less than or equal to 25MW/minute and the reserve needs to be sustainable for 15 minutes.

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.

Frequency Response

The electricity SO has a statutory obligation to maintain system frequency between+/- 1% of 50 hertz. The immediate second-by-second balancing to meet this requirement is provided by continuously modulating output through the procurement and utilization of mandatory and commercial frequency response.

G

Gas Transporter (GT)

Formerly Public Gas Transporter (PGT). GT's, such as Northern Gas Networks, are licensed by the Gas and Electricity Markets Authority to transport gas to consumers.

I

Income Adjusting Event (IAE)

NGET and NGG are able to submit notices to Ofgem under their respective licences of proposed income adjusting events if costs (or savings) are incurred in connection with their SO activities that were not envisaged at the time an incentive scheme was agreed.

Intertrip

Intertrips are required to strategically manage power flows on the system, and remove at short notice potentially vulnerable circuits.

L

Linepack

The volume of gas within the National or Local Transmission System at any time.

N

National Transmission System

A high pressure system consisting of terminals, compressor stations, pipeline systems and offtakes. Designed to operate at pressures up to 85 bar. NTS pipelines transport gas from terminals to NTS offtakes.

O

On the day Commodity Market (OCM)

This market enables anonymous financially cleared on the day trading between market participants.

Operating Margin (OM) (in gas)

Gas used to maintain system pressures under circumstances including periods immediately after a supply loss or demand forecast change before other measures become effective and in the event of plant failure, such as pipe breaks and compressor trips.

Operating Margin (OM) (in electricity)

This is a requirement at the day-ahead stage to ensure that the system security can be properly managed across Power Exchange and Balancing Mechanism time-scales, i.e. 'up to' and 'at real time'.

Own Use Gas

Gas used by system owners to operate the transportation system, this includes gas used for compressor fuel, heating and venting.

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.

S

Sharing factors

These describe the percentage of profit or loss which the System Operator will be subjected to if the relevant incentive performance measure falls below or exceeds the relevant incentive target.

Shrinkage

Gas that is input to the system but is not delivered to consumers or injected into storage. It is either Own Use Gas or Unaccounted for Gas.

Sliding Scale

This term is used to describe incentive schemes which involve profit (and loss) sharing around a fixed target cost.

System Average Price (SAP)

This is the price in pence per kWh calculated as the sum of all Market Transaction charges divided by the sum of the Trade Nomination Quantities for all transactions effected in respect of that day, subsequently adjusted to account of any bids which are to be excluded in association with resolving constraints.

System Operator (SO)

This is the entity charged with operating either the GB electricity or gas transmission system. NGET is the operator of the high voltage electricity transmission system for GB. NGG is the operator of the gas NTS for GB.

T

Transmission losses

This is the electricity lost on the GB transmission system through the physical process of transporting electricity across the network. The treatment of transmission losses is set out in the BSC.

U

UK Continental Shelf UKCS

The UK Continental Shelf (UKCS) comprises those areas of the sea bed and subsoil beyond the territorial sea over which the UK exercises sovereign rights of exploration and exploitation of natural resources.

Appendix 4 - 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:

Andrew MacFaul
Consultation Co-ordinator
Ofgem
9 Millbank
London
SW1P 3GE
andrew.macfaul@ofgem.gov.uk