Promoting choice and value for all gas and electricity customers

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

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Target audience: This document will be of interest to network owners and operators, generators, shippers, suppliers, customers and other interested parties.

Overview:

National Grid Electricity Transmission plc (NGET) is the system operator (SO) for the electricity transmission system in Great Britain (GB), and National Grid Gas plc (NGG) is the SO for the gas transportation system. This document and the supplementary appendices document set out our initial proposals for SO incentive schemes for NGET and NGG to apply from 1 April 2007. This document invites feedback from interested parties on a number of questions set out in it. Following consideration of respondents' views and market conditions we will develop our final proposals including statutory licence consultations for the incentive schemes. These will be published in February 2007.

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Context

This project is part of our overall work to regulate monopolies effectively. In both gas and electricity we consider it is important that the system operators are appropriately incentivised to operate their systems in an economic and efficient manner.

We believe that it is appropriate to develop incentives schemes that provide NGET and NGG with an appropriate balance of risk and reward which is in the interests of customers, who ultimately pay for the costs of system operation.

Associated Documents

- National Grid Electricity Transmission and National Grid Gas System Operator Incentives from 1 April 2007: October consultation: 2 October 2006

http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/16920_179_06.pdf

- National Grid Electricity Transmission and National Grid Gas System Operator Incentives 2007-08 - Invitation to Submit Views: 5 July 2006

http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/15627_Open_letter_on_NGET_historical_performance_v2.pdf

- Transmission Price Control Review: Final Proposals: 4 December 2006

http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/17916_20061201_TPCR_Final_Proposals_in_v71_6_Final.pdf

- Ofgem's Transmission Price Control Review: Updated Proposals: 25 September 2006

http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/16855_170_06.pdf?wtfrom=/ofgem/whats-new/archive.jsp

- Transmission Price Control Review: Draft Licence Modifications: 15 November 2006

http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/17587_197_06.pdf

- Determination under Special Condition AA5A Part 2 (i), paragraph 12(a) of National Grid Electricity Transmission plc's Transmission Licence in respect of Scottish Constraints and CAP047: 25 September 2006

http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/16856_171_06.pdf

Table of Contents

Summary

In this document we set out our initial proposals for the system operator (SO) incentive schemes for NGET and NGG to apply from 1 April 2007. We have so far consulted twice on these schemes, in an open letter in July 2006 and in our preliminary views in October. We summarise respondents' views to the October consultation in this document.

Updates on NGET's and NGG's SO cost forecasts

Since the October consultation, there has been a further decline in wholesale gas and electricity prices, which has led to NGET revising its forecast level of external costs for 2007/08 to £458 million, compared to its previous forecast of £483 million.

All other NGET and NGG forecasts remain unchanged:

- NGET forecasts operating expenditures (opex) of £251 million and capital expenditures (capex) of £47 million for the five-year period from 2007/08 to 2011/12 for its SO business. Throughout this document, all figures relating to internal SO incentives are in 2004/05 prices.
- NGG forecasts gas cost (shrinkage) volume and gas reserve volume requirements for 2007/08 of 7,750GWh and 1,589GWh respectively (central case projections).
- NGG forecasts internal gas SO costs for the five year period from 2007/08 2011/12 to be £126 million for opex and £64 million for capex.

Our initial proposals

For electricity, we are proposing an external SO incentive scheme for 12 months (from 1 April 2007), which retains a single cost target. Having analysed NGET's forecast of costs we consider that there are grounds for cost savings. We present four options, shown below and invite views on each of these schemes. We consider that each of these options represents a fair balance of risk and reward between NGET and customers.

	IBC Target	Upside (reward to NGET if costs are below target)		Downside (penalty to NGET if costs are above target)	
	£m	Sharing factor	Cap (£m)	Sharing factor	Floor (£m)
Option 1	440	7.5%	5	10%	5
Option 2 (with indexation and price risk band)	430	7.5%	5	10%	5

Option 3	430	30%	10	15%	10
Option 4	415	50%	20	10%	10

For the first time, we are presenting an option where elements of the external cost incentive scheme will be indexed to wholesale prices if prices move outside of a certain range (option 2). This option protects against NGET receiving either windfall gains or losses due to large movements in wholesale prices.

In this document, we also set out our proposals for electricity internal SO costs, where adjustments have been made from our preliminary view on operating costs (increasing the allowance by £20.5 million), pensions (increased allowance of £19.7 million). Our initial proposal for NGET's total internal allowed revenue for the period 2007/08 to 2011/12 is £411.5 million.

For gas external costs we are proposing a one year incentive scheme, with a rollover of the existing sharing factors and parameters for gas shrinkage, system reserve, residual balancing and for the information incentives. However, given the continued uncertainty that exists regarding the volume of shrinkage gas that will be required in 2007/08, we are proposing to base the target volume for gas shrinkage on actual flows through the St Fergus terminal. We are also proposing reviewing the prices that are applied to the gas reserve incentive, and introducing a new licence condition on NGG to introduce competition in the market for gas system reserve in the next two years. We are also consulting on the introduction of a new incentive designed to ensure that NGG faces an appropriate cost for emitting methane from the NTS.

For NGG's gas SO internal costs, we have made an upward adjustment in our allowances for capital expenditures (£7.2 million), and pensions (£1.7 million) but have lowered our allowances for tax (£5.8 million).

For both gas and electricity internal SO costs, we have put forward new proposals regarding the sharing factors applicable to capital expenditure, and have included questions related to the appropriate alignment of sharing factors for operating expenditures. In addition, we present a proposal from NGET and NGG for an automatic adjustment mechanism for incremental costs related to commercial framework modifications.

Next steps

We will consider feedback we receive to this consultation, including that provided by NGET and NGG, in developing our final proposals and statutory licence consultation. When developing our final proposals we will also take account of the latest wholesale prices, and the effects of recent rule changes. We expect to publish our final proposals in February 2007.

In our previous documents we additionally set out our plans to conduct a review of the external SO incentive schemes for gas and electricity to apply from April 2008 onwards. At the request of one respondent, we have attached draft terms of reference for this review to this document. We expect to start work on this project in April 2007, subject to other priorities.

1. Introduction

Chapter Summary

This chapter provides a short background of 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. In July we published an open letter inviting interested parties' views on the historical performance of NGET and NGG as the respective electricity and gas SOs, and on the scope and form of the electricity and gas SO incentive schemes to apply from 1 April 2007. Following receipt of NGET's and NGG's initial forecasts of their SO costs and, where appropriate, volumes for 2007/08, we published a Preliminary Views consultation in October. That document also included background on the SO incentive schemes.

1.2. We received thirteen responses to the October consultation. A summary of these responses can be found in Appendix 5.[1] Overall, respondents were supportive of the process that Ofgem is adopting for setting both the internal and external incentive schemes. We have outlined the comments of respondents on each of the issues in Chapters 2 and 3.

1.3. In addition to receiving respondents' views to the October consultation, we have now received further information from NGET and NGG. All of this information has helped us to develop our initial views for SO incentive schemes to apply to NGET's and NGG's external and internal SO costs from 1 April 2007 which are discussed in this document.

Structure and approach

1.4. This initial views consultation document consists of four chapters. This chapter provides background, and outlines the process we are following in developing SO incentive schemes for NGET and NGG from 1 April 2007, the structure of the document and the way forward.

[1] The responses in full are available on the Ofgem website www.ofgem.gov.uk.

1.5. In Chapter 2 we discuss our initial proposals for electricity SO incentive schemes to apply to NGET's external and internal SO costs from 1 April 2007. We explain how these initial proposals have been informed by NGET's revised forecast, responses to our October consultation and recent market events. Similarly, Chapter 3 outlines our initial proposals for gas SO incentive schemes to apply to NGG's external and internal SO costs from 1 April 2007, while in Chapter 4 we briefly summarise our next steps. Further details are provided in appendices in this document and in a supplementary document.

Way Forward

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

1.7. Responses should be sent to wholesale.markets@ofgem.gov.uk, to be received no later than **16 January 2007**. Further details of how to respond can be found in Appendix 1.

1.8. We will consider feedback we receive to this consultation, including that provided by NGET and NGG, in developing our final proposals and statutory licence consultation, with a view to agreeing SO incentive schemes with NGET and NGG to apply from 1 April 2007. When developing our final proposals we will also take account of the latest wholesale prices, and the effects of recent rule changes. We expect to publish our final proposals in February 2007.

1.9. If NGET and NGG consent to our final proposals, the incentive schemes would be effective from 1 April 2007. If either NGET or NGG do not accept our final proposals, we would have to decide whether to refer the matter to the Competition Commission, or to rely on our existing powers for the purposes of regulating NGET and/or NGG.

2. Electricity SO incentive schemes

Chapter Summary

This chapter outlines our initial proposals for SO incentive schemes to apply to NGET's external and internal SO costs from 1 April 2007. In this chapter we summarise respondents' views to the questions set out in the October consultation and present NGET's revised forecast for external incentivised balancing costs (IBC). We also set out our analysis of this forecast and, based on this, present four options for external balancing costs.

Question box

Question 1: What are your views on NGET's revised forecast of £458 million? In particular, do you consider that there are any areas where NGET is being risk disposed or risk averse in its assessment of costs? Alternatively do you consider that there are any drivers of cost that NGET has not identified?

Question 2: In this chapter we identify areas where we believe that NGET has over forecast its costs. Do you agree with our assessments? Please provide as much analytical detail as possible in your response.

Question 3: Within NGET's forecast a continued area of increasing cost is mandatory frequency response costs. What do you consider to be the drivers of costs for frequency response? What impact do you consider that CAP107 will have on these costs? Do you believe there is scope for cost reductions as competition is established in the provision of these services?

Question 4: NGET is forecasting that constraint costs will continue to be of the order of £81 million. Do you consider that there is any scope for reductions in these costs?

Question 5: In November, a significant change was introduced to the electricity cash out arrangements (Modification P205). What is your assessment of the impact of this change on NGET's forecast level of costs? Please provide as much analytical detail as possible in your response.

Question 6: Do you think it is appropriate that we take into account the then current wholesale market conditions when setting the IBC target in the final proposals?

Question 7: What do you think is an appropriate level of IBC for 2007/08?

Question 8: Do you have any comments on our indexation analysis? Specifically, do you support the way in which indexation has been applied in the option we have proposed? Do you have any comments on our approaches to determining the adjustment factor? Are there any alternative approaches that we have not considered? Do you have any comments on the deadband size?

Question 9: What are your views on the four proposed options?

Question 10: Do you agree with our views on IAEs going forward?

Question 11: Do you have any comments on the draft Terms of Reference for a review of the external SO incentive scheme contained in Appendix 12?

Question 12: Do you agree with our Initial Proposals for levels of internal opex, capex, tax, and pensions allowances?

Question 13: What are your views on implementing fixed sharing factors for internal capital expenditures? Do you have a view on the level of these sharing factors? What are your views on the alignment of the operating expenditure sharing factors?

Question 14: Do you think incremental internal costs associated with modifications to commercial frameworks (e.g. BSC) should be remunerated through the existing IAE provisions or via a more automatic cost recovery process built around enhanced cost reporting and accountability to the industry through the existing commercial frameworks?

2.1. This chapter outlines details of our initial proposals for the electricity SO incentives. These proposals are described in turn for:

- the external electricity incentives, and
- the internal electricity incentives.

External SO incentive scheme

2.2. Our October consultation described our preliminary views on the scope and duration of the external electricity incentives. This section sets out our initial views on the remaining key issues regarding the external SO incentive scheme that will commence from 1 April 2007 next year (for one year). These views have been developed taking into account the responses to our October consultation, a revised forecast of external electricity SO costs for 2007/08 received from NGET and recent events in the wholesale gas and electricity markets.

2.3. In this section, we outline our initial views on:

- NGET's revised forecast of IBC and our views on this forecast,
- potential indexation of electricity incentives to electricity prices, and
- treatment of income adjusting events.

2.4. At the end of this section we provide a summary of the incentives options on which we invite respondents' views.

NGET's revised IBC forecast

2.5. For the October document, NGET forecast that IBC would be £483 million for 2007/08. In making its forecast NGET stated that it had been asked to produce these numbers earlier in the process than usual and therefore they were subject to revision. Accordingly, NGET provided us with a revised IBC forecast for 2007/08 on 23 October.[2]

2.6. In the remainder of this section we outline:

- NGET's revised cost forecasts, and
- Ofgem's views on this forecast.

NGET's revised cost forecasts

2.7. Wholesale prices for gas and electricity have been on a downward trend since the summer months, in part as a consequence of uncertainties associated with new import infrastructure in the gas system having decreased, and because oil prices have also reduced. Along with the majority of respondents, we considered in October that the conditions in the wholesale markets suggested that costs for 2007/08 were likely to be lower than NGET's initial forecast.

2.8. Following the release of the October consultation, NGET revised its forecast for external costs. This revised forecast was £25 million lower than the previous forecast (falling from £483 million in July to £458 million in October).

2.9. Table 2.1 shows NGET's October forecast compared to the July forecast, its expected costs for this year as at 23 October,[3] as well as the actual costs for 2005/6.

[2] The public version of the information provided to us by NGET is reproduced in Appendix 6.
[3] NGET has subsequently amended its expected costs for 2006/07 to £481, further information is provided in its submission contained in Appendix 6.

Table 2.1: External SO costs - 2005/06 to 2007/08 (£ million)[4]

	2005/06 (Actual)	2006/07 (Estimate)	2007/08 (July forecast)	2007/08 (October forecast – mean)
Balancing Mechanism (excluding constraints)	190	98	152	152[5]
Balancing Services Contract Costs (excluding constraints)				
Ancillary services	228	298	313	317
Trades	59	39	47	15
Constraints	80	93	72	81
Transmission loss adjustment	(6)	4	0	0
Less: Net imbalance adjustment	(104)	(68)	(101)	(107)
Total	428	463	483	458

2.10. As well as providing a revised overall forecast for 2007/08, NGET also provided high, central and low scenarios. These were for £508 million, £453 million and £423 million respectively. The mean level of costs of these scenarios is £458 million.

2.11. NGET stated that the key driver for changes in its forecast was a fall in wholesale prices and lower volumes based on the experience of summer 2006. However, these were partially offset by increases in its forecasts for constraint costs and price of ancillary services (based on recent events).

2.12. A more detailed breakdown of NGET's forecast for individual Ancillary Service costs is provided in Table 2.2 below.

[4] All data in money of the day. Numbers may not total exactly as a result of rounding.
[5] As a result of its different forecasting methodology and allocation of costs, despite the fall in wholesale prices, NGET's forecast of total Balancing Mechanism costs has not altered from its July forecast.

Table 2.2: Ancillary Services costs - 2005/06 to 2007/08 (£ million)[6]

	2005/06 (Actual)	2006/07 (Estimate)	2007/08 (July forecast)	2007/08 (October forecast – mean)
Reactive Power	55	55	64	54
Frequency Response	65	108	106	114
Fast Reserve	37	41	39	41
Standing Reserve	42	62	65	69
Other Reserve (inc SO - SO fees)[7]	6	6	7	7
Warming	7	9	12	12
Black Start	15	16	19	18
Other	1	2	2	2
Total	228	298	313	317

Ofgem's views on NGET's revised forecast

2.13. Our views on the key drivers of the change in NGET's cost forecasts are outlined in turn below. These are:

- changes in wholesale electricity prices,
- frequency response issues,
- cost of constraints, and
- treatment of transmission losses.

2.14. We also provide a summary of our views on NGET's revised cost forecasts at the end of this section.

Wholesale electricity price changes

2.15. Respondents to the October consultation shared Ofgem's opinion that recent falls in wholesale electricity prices indicated NGET's initial SO external cost forecast was too high, and should be revised downwards to reflect more recent forward wholesale prices.

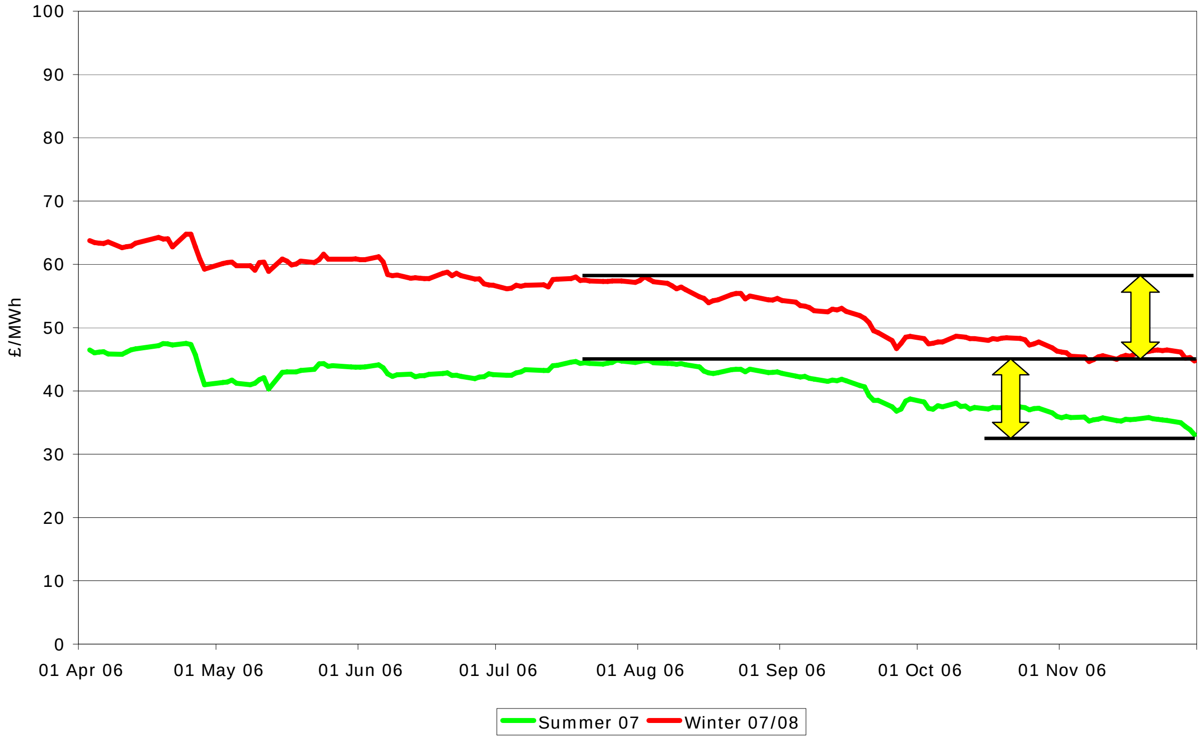
2.16. In July 2006, forward wholesale baseload prices were £44/MWh and £58/MWh for summer and winter 2007/08 respectively. Since then, these prices have fallen significantly (to around £33/MWh for summer baseload and £45/MWh for winter baseload). These price falls are illustrated in Figure 2.1.

[6] All data in money of the day. Numbers may not total exactly as a result of rounding.
[7] SO-SO energy costs are included within Balancing Mechanism costs and are not included within Ancillary Services Costs.

2.17. Note that NGET's revised forecast is based on summer prices of £38/MWh and winter prices of £48/MWh (i.e. the forward prices at the time NGET undertook its revised forecast which are higher than current price levels). In the event that wholesale electricity prices change significantly over coming weeks, we would expect this to be reflected in our final proposals for NGET's overall IBC target.

2.18. **We expect that there is further room for reduction of the IBC forecast, based on the continuing reduction in wholesale prices, and would welcome views on this**.

Figure 2.1: 2007/08 Forward Prices[8]



Frequency response

2.19. Since the introduction of CUSC Amendment Proposal 047 (CAP047), frequency response holding prices have increased considerably. These increases are partly a reflection of the underlying conditions including the removal of an administered price. However, given the extent of the increase and the scope for cost savings we consider that it is important to ensure that the level of costs that

[8] Source: Heren UK OTC power price assessments

NGET is forecasting is economic and efficient. We also consider it is important that the costs that NGET is facing are a consequence of a competitive market in frequency response provision.

2.20. Respondents to the October consultation generally considered that the continuing escalation of frequency response costs is concerning. Some respondents expected these costs to level off for a variety of different reasons including the impact of the recently approved CUSC amendment 107b (CAP107). One respondent suggested it may be necessary to review CAP047 if the intended impact (of CAP107) is not realised.

2.21. NGET has adjusted its forecast for frequency response costs by a reduction of £5 million for CAP107. However, NGET is still forecasting that frequency response costs will continue to rise from current levels.

2.22. Over summer 2006, there was a noticeable levelling out of the cost of frequency response. However, there have been some recent increases in these costs. Despite these recent increases, **we do believe there is scope for further downward pressure on these costs as wholesale prices have reduced considerably, and also as a consequence of the potential impact of CAP107.**

2.23. In Appendix 7, we outline additional analysis relating to frequency response costs. This analysis concludes that some parties (e.g. those with coal and older gas units) may have significantly increased their offered holding prices for frequency response beyond that which would be expected given their underlying costs. We would welcome views on this analysis. Following consideration of respondents' views, we will consider if it would be appropriate to take any further action with regard to either the operation of the frequency response market, or the actions of individual companies.

Constraints

2.24. Those respondents who addressed the question relating to internal Scotland constraints offered mixed views. Two respondents considered there should be some scope for cost savings. A further respondent suggested the interaction between Scottish constraint costs and TO investment should be examined to ensure the incentives under the SO incentive scheme and the Transmission Price Control Review (TPCR) are properly aligned.

2.25. Other parties expressed the view that, given that NGET appears to have limited options with respect to alleviating certain constraints even under the intact network conditions in Scotland, the bidding behaviour of relevant companies should be closely scrutinised.

2.26. As outlined above, NGET's actual constraint costs in 2005/06 were £80 million. Taking this into consideration, as well as confidential data submitted to Ofgem regarding the nature of existing contracts for the provision of constraint management services, we consider there to be a number of areas in which the costs of constraints in 2007/08 could be reduced further. In the event that outturn constraint costs remain at the high end of expectations, we will need to be satisfied that NGET has been doing all it can to mitigate these costs (such as evidence of appropriate long term contracting, investment in networks or highlighting areas of potential abuse of market power by generating companies to Ofgem).

2.27. In summary, **we consider that NGET's current forecast of £81 million could be reduced further, and would welcome respondents' views on the possibility and extent of any such reductions**.

Transmission losses

2.28. 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 Transmission Losses Reference Price (TLRP), which to date has been set ex ante.

2.29. In our July letter, we stated that one of the difficulties in setting the transmission losses incentive was determining ex ante the reference price to translate the difference between actual and target losses volumes into a financial incentive.

2.30. The majority of respondents to our July letter supported the continued inclusion of transmission losses in the IBC target, and also considered that a dynamic reference price should be used. No party expressed opposition to using a dynamic reference price.

2.31. In its October forecast, NGET's mean volume of transmission losses for 2007/08 is 5.82 TWh. Its forecast for net losses (i.e. outturn against target) is zero. NGET has used the period October 2005 to September 2006 as the base period for is forecast, during which time total transmission losses were 5.778 TWh. NGET has forecast different volumes of losses for each of its scenarios and states that the variability of losses in each scenario is a result of different locational generation and varying transfers across the French interconnector.

2.32. **Our initial proposal is to accept NGET's forecast of the volume of transmission losses as it appears to be reasonable, particularly given the changes in the location of generation. We also propose no changes in the methodology (i.e. ex ante) for pricing of transmission losses, except in the event that our Final Proposals include the indexation of the external incentive to wholesale electricity prices (discussed in more detail in the next section)**.

Summary of expected IBC

2.33. Given the combined impacts of additional wholesale price reductions, and the potential for the actions of both NGET and other market participants to deliver more economic and efficient frequency response and constraint costs, **we believe there is the opportunity to reduce the expected target level of IBC to approximately £430 million. We welcome respondents' views on this.**

2.34. As mentioned previously, we will monitor the movements of wholesale electricity prices, as well as the impacts of rule changes and will amend the IBC target in the Final Proposals accordingly.

Price indexation

2.35. In the October consultation we set out a potential new approach to incentivising NGET on external costs. In particular, we discussed the possibility of linking elements of the incentive scheme to an index of wholesale electricity prices. This proposal was designed to protect customers and NGET from windfall gains or losses as a consequence of large movements in wholesale prices.

2.36. We noted that we did not think it appropriate to remove completely all price risk from the SO, as it has tools available to it to manage price risks, including contracting ahead. We therefore discussed the possibility of including a "price risk band" around wholesale prices that would provide the appropriate incentives for NGET to manage risk, but would also be sufficiently flexible to adjust for structural changes in the wholesale markets.

2.37. The majority of respondents were supportive of some form of indexation. Some respondents pointed out that indexation could be a transparent form of an Income Adjusting Event, that would be symmetric to both rises and falls in prices. However, there were differing views of the form (e.g. whether a price risk band should be included), and the extent to which NGET should continue to be exposed to price risk. NGET supported some price incentive remaining on the SO, but also supported further consideration of the indexation proposal.

2.38. Several respondents also noted that including a method of indexation would result in a more complex scheme and it was important that the correct incentives remained on NGET.

2.39. In light of these comments, we continue to believe there is merit in putting forward an indexation option for consideration and have developed that option further.

2.40. As a first step in defining an indexation proposal, we examined the relationship between IBC and wholesale electricity prices, both in terms of overall IBC, in terms of its components and over differing time periods (i.e. earlier years and more recent history). Further details of this analysis are provided in Appendix 8.

2.41. NGET has suggested that total IBC should be indexed to wholesale prices. However, our view is that only certain elements of the IBC should be related to changes in the wholesale price of electricity. For example, it seems likely that the costs of providing reserve are related to wholesale energy prices as the opportunity cost to generators of providing reserve is the price of energy that they might have earned in the wholesale market. Conversely, the costs of resolving constraints might be less related to wholesale prices, as the price of the offsetting buy and sell trades required to solve a constraint would tend to rise or fall by the same amount, implying no net increase or reduction in costs to NGET.

2.42. Overall, those actions that NGET undertakes for energy reasons would be expected to change with movements in wholesale prices whereas system related trades would not. We therefore consider that there are two potential options to selecting which elements should be included as part of the indexation. This could either be through:

- a **statistical approach**, in which selection of components is based on an analysis of historical data to evaluate which components of the incentive have historically moved with wholesale prices, or
- a **categorisation approach**, in which components are selected based on which elements are most likely to be "energy" trades rather than "system" trades (such as trades relating to balancing mechanism costs, forward trades, all reserve and reactive power).

Statistical approach

2.43. The coefficients selected for indexation under this approach are outlined in full in Appendix 8. This approach uses regression analysis to assess the strength of the correlation between each variable and wholesale electricity prices.

2.44. Our analysis has shown that, while some elements of the overall IBC incurred by NGET have a close relationship to the wholesale price, others have little or no link. For example, the relationship between the cost historically incurred by NGET in the provision of reactive power and the wholesale price of electricity is very close (with an R-squared of 0.98), while the costs associated with the provision of Pre Gate Closure Balancing Transactions (PGBTs) appears not to be linked to the wholesale electricity price (with an R-squared of 0.01).

2.45. We recognise that such an approach does have its limitations, and therefore would welcome any views in respect of alternative approaches.

2.46. After selecting those variables most correlated with electricity prices[9], we assessed the impact on the overall IBC target of changes in wholesale electricity prices. As we set out in Appendix 8, our analysis showed that the overall impact on the IBC of a £1/MWh change in the wholesale price is around £3.5 million.

Categorisation approach

2.47. As described above, an alternative approach would be to select those categories of IBC that conceptually seemed most likely to be energy related. This would therefore not include categories of IBC that relate to "system" related (e.g. trades relating to the relief of constraints), but would include those categories of trade that are "energy" related (e.g. balancing mechanism costs, forward trades and reserve). In addition, we have included reactive power as the cost of this service is indexed to wholesale prices.[10]

2.48. Further details of this approach are presented in Appendix 8. Under this approach we also assessed the impact on the overall IBC target of changes in wholesale electricity prices and found the overall impact on the IBC of a £1/MWh change in the wholesale price to be around £4.7 million.

2.49. **We welcome respondents' views on the concept of price indexation, and on the two proposed approaches to the selection of the components of IBC to which indexation should be applied. We would also welcome views on whether the components of IBC we have analysed sufficiently capture the sensitivity of the IBC target to wholesale electricity prices**.

2.50. Also in Appendix 8 we have included analysis that considers the possibility of a deadband. This suggests that a change in prices of more than 10% may be indicative of a "structural break", and may be the appropriate level for a deadband. We believe NGET should be capable of managing the risks of price changes less than 10%. Therefore, if prices increase or decrease by more than 10%, the target IBC would be adjusted for every additional 1 £/MWh change in outturn wholesale prices above the 10%. We would welcome views on this analysis.

Income Adjusting Events

2.51. Most respondents to the October consultation supported the continuation of Income Adjusting Event (IAE) provisions, but expressed concern about the lack of

[9] As outlined in Appendix 8, we considered those components of IBC with an R-squared in excess of 0.7 to be most sensitive to changes in wholesale electricity prices.
[10] We note that this categorisation into system and energy is not the same as that used elsewhere.

transparency and the information asymmetry that favours NGET in the IAE process.

2.52. NGET characterised IAEs as two types: those that have been flagged as potential issues prior to the start of the incentive scheme, and those that would not have been foreseeable in advance, such as force majeure events. NGET argued that the former are not necessary for 2007/08 and could be eliminated, but if Ofgem were to consider eliminating the latter type, that a 'risk premium' should be added to the expected IBC target to account for the uncertainty and consequence of such events arising.

2.53. **We are proposing to retain the current IAE provisions for this incentive scheme for all options except the proposal that we have developed for an indexed scheme. If we were to proceed with the option of an indexed scheme then we believe that NGET should only be eligible to raise an IAE on those costs that are outside of the price index.**

Summary of proposed options

2.54. Based on our current view of expected IBC outturn of £430 million, we have designed four possible options reflecting different risk/reward trade offs around an IBC target. We welcome views on these options. As discussed above these options may be amended prior to the Final Proposals in light of additional information that becomes available. These options are summarised in Table 2.3 below.

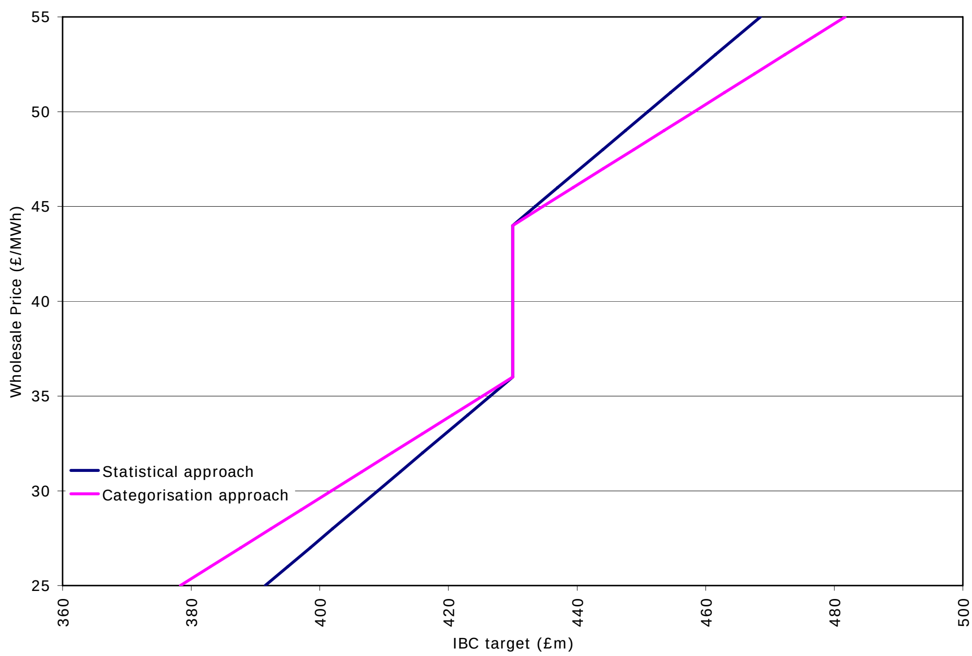
Table 2.3: Options for initial proposals

	Target	Upside (reward to NGET if costs are below target)		Downside (penalty to NGET if costs are above target)	
	£m	Sharing factor	Cap (£m)	Sharing factor	Floor (£m)
Option 1	440	7.5%	5	10%	5
Option 2 (including indexation and price risk band)[11]	430	7.5%	5	10%	5
Option 3	430	30%	10	15%	10
Option 4	415	50%	20	10%	10

[11] See Appendix 8 for more details on the structure of this option.

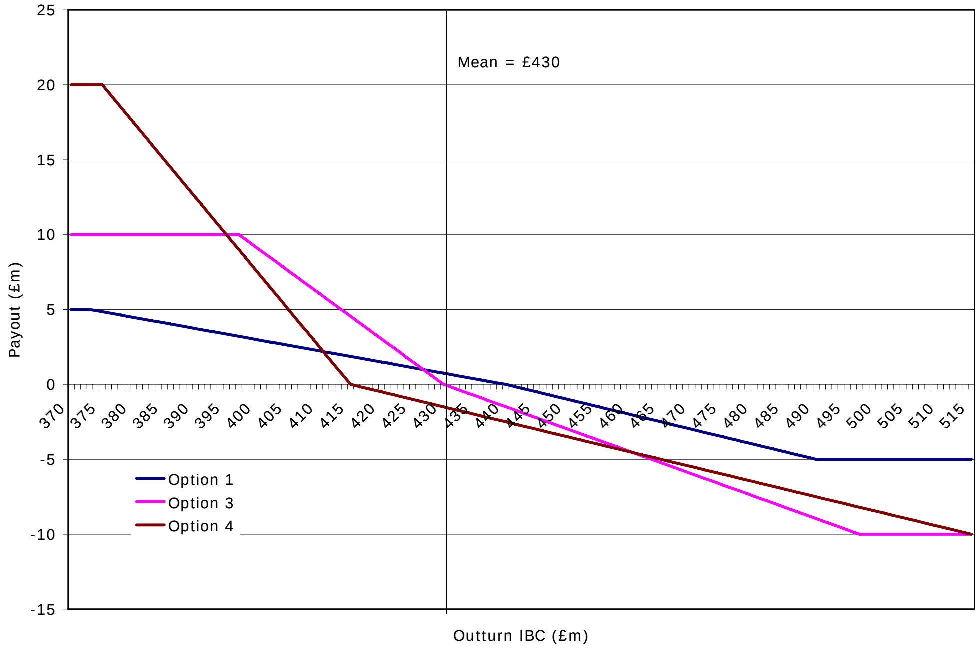
2.55. We have designed these options to enable NGET to choose an option based on its own risk/reward appetite and where it considers IBC will outturn. Option 1 has been designed to reflect an outcome should NGET take a very risk averse approach, while still representing an £18 million reduction from NGET's October forecast. Option 2 includes an indexation option. As outlined above, this has been designed with the same low risk parameters as Option 1, with the exception of a slightly lower target, as this option removes some of the risk to NGET of wholesale prices increasing. The effect of the deadband on this option is shown in Figure 2.2, in which we assume an agreed price of 40£/MWh.

Figure 2.2: Effect of deadband on IBC target under option 2



2.56. The potential incentive payouts under Options 1, 3 and 4, at various outturn IBC levels are shown in Figure 2.3 below. Option 2 would be similar to Option 1 (albeit with a lower starting target), but the potential incentive payout line would shift to the left or right if the wholesale price exceeded the price risk band.

Figure 2.3: Potential Incentive Payout vs Outturn for Incentive Scheme Options



2.57. As outlined in Appendix 8, if we assume that our agreed view of expected wholesale prices for 2007/08 was £40/MWh (the basis on which the IBC target is agreed), then the deadband would be +/- £4/MWh. Therefore, under Option 2, if the wholesale price outturned at £34/MWh the target would be reduced to £423.1 million. As the sharing factors are also relatively small under this option (reflecting the lower risk level), any payouts to NGET would be relatively small, regardless of the reason for the lower outturn IBC.

2.58. Table 2.4 provides further examples of potential outcomes under the four options outlined above. This table shows that, for example, were IBC to outturn at £410 million, then under Option 1 NGET would receive a payment of £2.25 million, and under Option 2 (statistical approach) a payment of £0.98 million (if the indexation was not in place, but the other parameters stayed the same, the payout would be £1.5 million).

Table 2.4 Possible outcomes under the four options (£ million)[12]

	IBC Outturn £410m Wholesale Price £40/MWh	IBC Outturn £410m Wholesale Price £34/MWh	IBC Outturn £430 m Wholesale Price £40/MWh	IBC Outturn £450 m Wholesale Price £40/MWh	IBC Outturn £450 m Wholesale Price £46/MWh
Option 1	2.25	2.25	0.75	-1.00	-1.00
Option 2	1.50/1.50	0.98/0.80	0.00/0.00	-2.00/-2.00	-1.31/-1.06
Option 3	6.00	6.00	0.00	-3.00	-3.00
Option 4	2.50	2.50	-1.50	-3.50	-3.50

2.59. Appendix 9 sets out draft licence modifications related to the numerical section for the four options outlined above.[13]

Internal SO incentive scheme

2.60. In our October consultation, we set out our preliminary views for the duration and scope of the internal electricity SO incentive scheme. In light of respondents' comments, we propose no changes to these.

2.61. The remainder of this section focuses on changes to the form of the internal incentive and new issues that have arisen. These are:

- the proposed changes in NGET's internal incentivised costs,
- treatment of the roll forward of the Regulatory Asset Value (RAV), the associated sharing factors related to capex and opex, and
- internal costs associated with future modifications to commercial frameworks.

NGET's internal incentivised costs

2.62. In the October consultation, we provided our views on the level of internal SO costs for 2007/08 to 20011/12. In response to respondents' views, we believe it is appropriate to adjust the allowance for operating expenditures (opex), taxes and pensions. We propose no changes to our position on capital expenditure (capex).

[12] Under Option 2, the first number relates to the statistical approach, the second number to the categorisation approach.
[13] For the avoidance of doubt, Appendix 9 does not contain the complete licence drafting. Licence drafting is being coordinated with the Transmission Price Control Review. Partial drafting was included in the 15 November 2006 document "Draft Licence Modifications". Additional revisions will be included in a January consultation.

2.63. Table 2.5 below summarises the changes to our position since the October consultation. Detailed revenue calculations are set out in Appendix 10.

Table 2.5 NGET Internal SO Costs Update for 2007/08 to 2011/12 for Initial Proposals (£ million, 2004/05 prices)

	NGET Forecast	Ofgem Initial Proposals	Change from Sept
Opex	251.5	248.2	+20.5
Capex (Incentivised)	46.9	41.0	no change
Tax	n/a	2	+2
Pensions	n/a	76.2	+19.7

2.64. Following responses to the October consultation, we have adjusted our opex profile to reflect fully ongoing cost levels post BETTA implementation allocations from the TO price control. Combined, this results in an upward adjustment of £20.5 million to opex - for a five year total allowance of £248.2 million.

2.65. On the tax allowance, we previously determined a zero tax allowance, which did not take account of certain elements of depreciation. Making this adjustment results in a five-year tax allowance of £2 million.

2.66. For the pension allowance, in the October consultation, we split NGET's total pension costs (SO and TO) using the TO rate of capitalisation. However, the SO capitalisation of direct staff costs is almost negligible. Making the adjustment leads to an increase in the allowance of £19.7 million.

2.67. In addition to the incentivised capex allowance above, the SO also has a non-incentivised capex which is the depreciated balance of the portion of the RAV attributed to NGET's SO internal incentive when it was split from the TO control in 2001. The IT component of non-incentivised capex is fully depreciated by 2007/08, causing total revenue to fall by £15 million in 2008/09. There is also the depreciated balance of capex that NGET was allowed for the implementation of BETTA.

2.68. Appendix 10 sets out detailed revenue calculations of the SO internal cost incentives for 2007/08 to 2011/12. **Our initial proposal sets total internal revenue at £411.5 million.**

Incentives and roll-forward of the RAV

2.69. The existing internal incentive applies sharing factors (upside and downside) to opex and incentivised capex. The sharing factors determine the proportion of over- or under-spend around the baseline allowance to be retained by the company. Currently, these sharing factors are aligned to those of the external incentive scheme.

2.70. For capital expenditure, there is an inevitable interaction between the sharing factors, the over expenditure incurred, and capital expenditure allowed into the internal RAV over the same period. NGET has stated that it would like to see consistency and certainty regarding incentives on capital expenditure incurred and expenditure allowed into the RAV.

2.71. NGET has proposed implementing a fixed incentive similar to that proposed by Ofgem for NGET TO capital expenditure.[14] In practical terms this would include the following:

- fixed sharing factors on capex over- and under-spend each year throughout the period of the internal incentive. The remaining proportion of over- and under-spend would be added to the RAV in each year, based on the TO incentive this would mean 75% of over-spends would be added to the RAV and 75% of under-spend would be deducted from the RAV.
- notwithstanding the above, a disallowance from the RAV of items of expenditure that are demonstrably inefficient or wasteful and an adjustment to claw back revenue recovered on such expenditure following an efficiency review at the next Price Control Review.

2.72. If respondents consider this proposal appropriate, then a subsequent issue is the level of the sharing factors associated with the fixed strength incentive. The proposed fixed strength incentive for NGET's TO capital expenditure is 25% for both over- and under-spends.

2.73. With regard to the choice of sharing factors for internal operating expenditures, we invite respondents' views on whether it is appropriate to align them with the capex sharing factors or remain aligned to the external incentive scheme, and whether the former would cause perverse incentives given the wide range of sharing factors associated with the external proposals.

NGET internal costs associated with future modifications to commercial frameworks

2.74. NGET has raised the issue of costs that it may incur above the baseline allowances related to items beyond its control. In particular, modifications to commercial frameworks such as the Balancing and Settlement Code (BSC) may require NGET to incur costs incremental to its internal cost incentive e.g. extra

[14] Transmission Price Control Review, Final Proposals, 4 December, 2006. Ref 207/06

staff or modification to commercial systems. The baseline allowances currently include £0.25 million each year for such costs.

2.75. As noted above, we intend to retain the income adjusting event (IAE) provisions, which would be one way of potentially remunerating NGET for these costs. The present IAE provision in the internal incentive has a threshold of £1 million.

2.76. NGET has highlighted a number of disadvantages with using IAEs for recovery of these potential costs. NGET believes the IAE process would not be sufficiently transparent and would be burdensome, given that such costs would have already been part of relevant modification consultations processes. NGET has stated a desire to see a more automatic cost recovery mechanism whilst maintaining transparency and accountability to the industry over such costs

2.77. One way to facilitate NGET's suggestion would be to introduce a licence term into the internal revenue restriction which would take on the value of incremental costs identified in approved/non-vetoed modifications each year. NGET would be required to report to Ofgem the costs (and the associated modifications) it would seek to remunerate against the licence term. NGET has also suggested it would provide regular e.g. (monthly) to the industry on costs it would be seeking to remunerate.

2.78. To be clear, the costs under consideration here are internal NGET costs that NGET has clearly identified as incremental to the existing baseline allowance, and excluding costs to Elexon, as part of the modification consultation process and in the final modification proposals. NGET proposes the following commercial frameworks would be covered by such a proposal:

- Balancing and Settlements Code (BSC),
- Connection and Use of System Code (CUSC),
- The GB charging methodologies,
- SO TO Code (STC),
- Balancing Services Adjustment Data (BSAD),
- Balancing Principles Statement,
- Procurement Guidelines, and
- Applicable Balancing Services Volume Data (ABSVD).

2.79. We invite comments from respondents on whether NGET should be remunerated for such internal costs, should they arise, by some alternative mechanism to the IAE provision.

3. Gas SO incentive schemes

Chapter Summary

This chapter outlines our initial proposals for SO incentive schemes to apply to NGG's external and internal SO costs from 1 April 2007. We summarise respondents' views to our October consultation and present our initial proposals for each component of the incentives schemes to apply from 1 April 2007.

Question box

Question 1: Do you agree with the proposed introduction of a new incentive to limit emissions of methane from the NTS from April 2007, and link this incentive to the prevailing price of carbon?

Question 2: Do you agree that the scope for all other components should remain the same as previous years for the external gas SO incentives?

Question 3: Do you agree with our proposal to vary the target for gas shrinkage on the basis of actual (2007/08) flows through St Fergus?

Question 4: Do you consider the proposed volumes for the shrinkage targets to be appropriate?

Question 5: Do you consider it is appropriate to retain the existing gas reference price methodology for the gas shrinkage incentive?

Question 6: Do you agree with our proposed target for gas reserve, and our intention to undertake a more fundamental review of this incentive in 2007?

Question 7: Do you agree with our proposal to review the reference prices that apply to the gas reserve incentive?

Question 8: Do you agree that, where market prices exceed reference prices for gas reserve, that the SO should pay these higher prices for OM gas?

Question 9: Do you agree with our initial proposals to retain the existing form of the residual gas balancing incentives?

Question 10: Do you have a view on the most appropriate form for the quality of information incentives in 2007/08? Do you consider these incentives should be revised in light of NGG's performance over winter 2007/08?

Question 11: Do you agree with our views on IAEs going forward?

Question 12: Do you agree with our Initial Proposals for internal costs?

Question 13: Do you agree that we should implement fixed sharing factors for internal capital expenditure? If so what should the level of the sharing factors be?

Should the operating expenditure sharing factors be aligned with the capex factors, or aligned to the external incentive?

Question 14: Do you think incremental internal costs associated with modifications to commercial frameworks (e.g. UNC) should be accommodated through the existing IAE provisions or via a more automatic cost recovery process built around enhanced cost reporting and accountability to the industry through the existing commercial frameworks?

3.1. This chapter outlines details of our initial proposals for the gas SO incentives. These proposals are described in turn for:

- the external gas incentives, and
- the internal gas incentives.

External SO incentive scheme

3.2. In our October consultation we outlined our views on both the scope and duration of the incentives, and respondents were generally supportive of our proposals. We did receive a number of comments regarding scope, however we continue to consider that it is more appropriate to address these issues in 2007 when we plan to undertake a more fundamental review of the gas SO incentives.

3.3. Since publication of our October consultation, we published our first Sustainable Development Report[15]. This document highlighted that Ofgem has a duty to have regard to the impact of the gas and electricity systems on the environment, and described a number of areas in which the operation of the gas network has a direct impact on the environment. One such area relates to methane emissions from the NTS. Methane (the gas that constitutes the majority of natural gas) is a greenhouse gas 21 times more potent than carbon dioxide.

3.4. NGG already has an incentive in place to limit the volume of gas shrinkage on the network, an element of which is the amount of "unaccounted for gas" lost from the network. However, this existing incentive does not identify the precise volume of methane lost from the NTS, nor does it link the value of lost methane to the prevailing cost of carbon.

3.5. For this reason, we are considering developing an additional incentive for NGG to limit the volume of methane emissions from the NTS. A key area of this work will involve understanding whether it is possible to measure the volume of methane emissions sufficiently accurately to enable a financial incentive to be

[15] Sustainable Development Report 2006, Ofgem, November 2006, 192/06.

placed on changes in such a measure[16]. In addition, we would need to understand in more detail how any such incentive would interact with the broader environmental regulatory framework.

3.6. In the coming months we plan to work with NGG to develop proposals in this area in more detail. However, our initial view is that it would be feasible to develop detailed proposals for such an incentive ahead of publication of our Final Proposals consultation in February 2007. We would invite views of respondents on whether the development of such an incentive would be appropriate for 2007/08, and the appropriate form for such an incentive.

3.7. With regard to the scope of the existing SO incentives (and in light of feedback from respondents), we continue to consider that the scope of the incentives should remain unchanged for the next 12 month incentive period. Therefore, **our initial proposal is that, aside from the potential addition of an incentive relating to methane emissions, the existing scope of NGG's external SO incentives should be retained.**

3.8. The remainder of this chapter outlines our initial views on the key remaining issues regarding the external gas SO incentives, namely:

- the costs associated with gas shrinkage (i.e. energy used as compressor fuel, unaccounted for gas and unbilled energy),
- the costs incurred by NGG to provide gas system reserve,
- the price and volumes (linepack) associated with residual gas balancing,
- the quality of information incentives, and
- treatment of income adjusting events.

Gas shrinkage incentive

3.9. The key issues to address with regard to the gas shrinkage incentive relate to:

- the appropriate volume of gas shrinkage to use in the incentive target,
- the pricing of shrinkage gas, and
- setting the remaining parameters for this incentive.

Gas shrinkage volume

3.10. Our October consultation outlined projections for an appropriate volume of gas shrinkage in 2007/08. NGG's central case projection of shrinkage volumes

[16] In this regard, we note that NGG is already required to have mechanisms in place to report estimates of both methane emissions as a consequence of the Environmental Protection Act.

required was nearly 25% higher than our preliminary view. We also provided an appendix that stated the key reason for this discrepancy resulted from different assumptions regarding the volume of flows through the St Fergus NTS entry terminal in 2007/08 (as levels of Own Use Gas (OUG) are strongly positively related to the volume of flows through St Fergus).

3.11. Most respondents commented on this issue, with four respondents stating that they considered that Ofgem's preliminary views on gas shrinkage seemed appropriate. Three respondents also stated they believed that there would be significant changes in network flows by 2007/08, resulting in a reduced level of compressor usage. No respondents (aside from NGG) supported NGG's projections.

3.12. On the basis of the views of respondents, we continue to consider that NGG's forecast levels of gas shrinkage in 2007/08 are overstated. However, we agree with NGG that there is a range of uncertainty regarding the volume of gas that may flow through St Fergus in 2007/08.

3.13. Given that NGG has no control over the volume of flows through St Fergus, and the sensitivity of levels of OUG to these flows, **we propose setting the shrinkage volume target on the basis of actual (outturn) level of flows through the St Fergus entry terminal**. We consider this will mitigate the potential for windfall gains or losses to both customers and NGG resulting from unexpected volumes of flows through St Fergus, and therefore represents a more appropriate allocation of risk.

3.14. We propose specifying three bands of flows through St Fergus, each of which would determine a different volume target. Our initial proposals for these bands, and associated shrinkage volumes are outlined below. In defining these volume targets, we have assumed that flows "displaced" from St Fergus (in the medium and low scenarios) instead enter the GB network through the Easington and Bacton terminals on a proportionate (50:50) basis to account for the uncertainty. We would welcome views of respondents on this assumption.

Table 3.1: Initial Proposals for shrinkage volume targets for 2007/08

Average flows through St Fergus	**Volume target (GWh)**
High (over 100 mcm/day)	8,312
Medium (85mcm/day to 100mcm/day)	7,129
Low (below 85mcm/day)	6,393

3.15. These proposals compare with NGG's original central case of 7,750GWh and our preliminary view (central case) of 6,216GWh.

3.16. **We invite views of respondents on our initial proposal to set shrinkage volume targets on the basis of outturn flows through St**

Fergus. We also invite views on whether the high, medium and low scenarios (and associated volume targets) are appropriate. Draft licence wording associated with this option is included in Appendix 9.

Gas shrinkage price

3.17. In our October consultation we stated that the existing gas cost reference price (GCRP) methodology should be retained for the 2007/08 incentive period. We did not receive any comments on this specific proposal. However we would reiterate that this methodology will be assessed in the fundamental review of gas SO incentives we intend to undertake in 2007.

3.18. Therefore, **our initial proposal is that the existing GCRP methodology should be retained for 2007/08**.

Gas shrinkage incentive sharing factors, cap and collar

3.19. In our October consultation, we suggested that the sharing factors, cap and collar should remain unchanged (at 25%, £4 million upside and -£3 million at 20% downside). Again, we received little comment on these proposals in response to our preliminary views. We therefore continue to consider that maintaining these parameters provides an appropriate incentive for NGG to manage the costs associated with gas shrinkage for the 2007/08 incentive period.

3.20. **Our initial proposal is therefore that the sharing factors, cap and collar for the gas shrinkage incentive should remain unchanged for 2007/08**.

System Reserve incentive

3.21. As with the gas shrinkage incentive, the gas reserve incentive target is also derived based on a volume projection and a pricing methodology. The key issues to be addressed with this incentive therefore relate to:

- the appropriate volume of gas reserve to use in the incentive target,
- the pricing of gas reserve, and
- determining the remaining parameters for this incentive.

Gas reserve volume

3.22. Our October consultation set out both NGG's view and our preliminary view of the most appropriate volume assumption to use in setting the financial target for the gas reserve incentive in 2007/08. In doing so, we highlighted a number of areas in which we considered NGG's forecasts overstated gas reserve requirements for 2007/08 (based on the findings of our independent technical consultant).

3.23. Five respondents to our October consultation stated that they supported the removal of any identified overlaps in reserve requirements, and two respondents considered NGG's forecasts for gas reserve seemed high. On the basis of respondents' views, we continue to consider there may potentially be areas where NGG's forecasts include double provision of reserve as a result of overlap between different reserve requirements. However, we believe that it would be most appropriate to address this issue when we undertake our fundamental review of the SO incentives next year. This will enable us to address this issue in a more holistic fashion, taking into consideration interactions with gas safety monitors and reform to the NTS offtake arrangements that will be undertaken in 2007.

3.24. However, we continue to consider that, in addition to the potential double provision of reserve, NGG's forecasts for gas reserve are overstated in that they:

- do not adequately reflect the increased responsiveness of shippers to major events, in light of improved real-time information, and
- understate the impact of improvements in the reliability of gas supplies (following the completion/anticipated completion of a range of gas importation infrastructure projects).

3.25. As such (and consistent with the views we outlined in our October consultation), we consider NGG's 2007/08 gas reserve forecast should be reduced by 39GWh. **Our initial proposal is therefore that a gas reserve target of 1,550GWh is appropriate for 2007/08. This represents NGG's central case, adjusted as described above.**

3.26. We would welcome views of respondents on our approach to the setting of the gas reserve incentive, and our proposal to undertake a more fundamental review of this incentive next year.

Gas reserve price

3.27. Currently, the prices applied to the system reserve volume projections in order to derive a cost target are set based on the prices specified for LNG storage services as outlined in special condition C3 of the gas transporter licence in respect of the NTS. We noted in our October consultation that the pricing arrangements for system reserve would be reviewed, with the potential for deviation away from using the special condition C3 prices.

3.28. Following this review, we have concluded that changes to elements of the existing regulatory regime are appropriate. We consider a priority to be the introduction of competition for the provision of system reserve (or OM gas) as soon as possible, the key reason for this being that, at present, National Grid plc is both the monopoly seller and buyer for the majority of OM gas. We consider that competition in this market is feasible, particularly with the planned development of a range of LNG facilities across the network over the next few years, and the increasing potential to contract for demand side response to meet system shortfalls.

3.29. To enable competition in this market to develop, NGG will need to develop standard contracts and procurement practices (in a similar fashion to existing arrangements in the market for electricity reserve). As a consequence, we plan to introduce a new NTS licence obligation as part of the Transmission Price Control Review proposals, requiring the NTS to develop and put in place the necessary arrangements to create conditions in which a market could be established for system reserve within 2 years.

3.30. We recognise that the C3 price caps were set prior to the current price control period, and that it is important that these continue to reflect an efficient, forward looking cost of the provision of LNG services. We therefore propose reviewing the level of the C3 price caps that will apply in the period before competition develops. We are currently assessing the appropriate level for any potential increase and will present our view on any such increase (and our rationale for doing so) in our February consultation document.

3.31. We also consider that the revised C3 prices should be the minimum that NGG NTS pays for system reserve. The LNG facilities are also used to provide commercial storage services. If the market price for these storage services is above the regulated price, then NGG NTS should pay the higher market price. Otherwise scarce capacity at these facilities will be being sold to the System Operator at a lower price than shippers and suppliers would be willing to pay to use that capacity. We believe that one potential way of achieving this (for the interim period) would be to link the C3 prices to a suitable reference market price for storage services provided commercially to shippers if such a market price is higher than the C3 price levels. We invite the views of respondents on these proposals.

3.32. Therefore, **our initial proposal is that the pricing arrangements for gas system reserve should be revised as outlined above.**

Gas reserve incentive sharing factors, cap and collar

3.33. The existing gas reserve incentive arrangements have 100% sharing factors, with no cap or collar on the incentive payment/receipt that NGG receives/faces. Historically, this approach has been adopted due to common ownership issues (given that NGG, as SO, procures its reserve services from the NG LNG facilities) and the absence of contestability in the provision of system reserve services.

3.34. We note that NGG has outlined its intention to purchase reserve services from independent third party providers over the course of the next price control period and we welcome developments in this respect. However, at present, the market is non-contestable. We therefore consider that it is appropriate to retain 100% sharing factors, with no cap or collar for the 12 month incentive period beginning 1 April 2007. We consider that this issue can be revisited in the context of our forthcoming review of NGG's external SO incentive arrangements to apply from 1 April 2008.

3.35. Therefore, **our initial proposal is that the sharing factors, cap and collar for the system reserve incentive should remain unchanged**.

Residual gas balancing incentives

3.36. The residual gas balancing incentive is designed to give the SO a financial incentive to make balancing trades at an efficient price, and also limit significant changes in end-of-day linepack. This section addresses remaining issues relating to these elements of this incentive.

Price incentive

3.37. We received no comments from respondents on our preliminary view that the parameters of the existing price incentive should be rolled over for a further year. We continue to consider that this approach will provide appropriate incentives for NGG to manage the costs associated with its residual balancing actions for 2007/08. As previously outlined, we are committed to conducting a fundamental review of NGG's shallow, external SO incentive arrangements during 2007. This will allow any potential changes to the structure and parameters of this element of the residual balancing incentives to be thoroughly evaluated.

3.38. Therefore, **our initial proposal is that the parameters for the price incentive should remain unchanged**.

Linepack incentive

3.39. We note that several respondents believe that the scope and purpose of the linepack incentive should be reviewed. We consider that this is best undertaken as part of the fundamental review that will take place during 2007. In light of the intention to undertake this review, we believe that it is appropriate to retain the existing framework for 2007/08, in order to maintain consistent incentives for NGG in its residual balancing role. Consequently, having considered the views of respondents, we continue to consider that the existing linepack incentive should be rolled over to apply for 2007/08.

3.40. Therefore, **our initial proposal is that the linepack incentive scheme parameters should remain unchanged**.

Quality of information incentives

3.41. The quality of information incentives, relating to both accuracy of day ahead gas demand forecasting and performance of NGG's website have been in place since 1 October 2006. These incentive arrangements were introduced as a direct result of proposals presented to (and developed by) the Demand Side Working Group.

3.42. Given the relatively short period of time over which these incentives have been in place, we have little data on which to assess their effectiveness. At time of publication, we have received data on NGG's performance for the first month of their operation (summarised in Appendix 11).

3.43. We received very few comments from respondents on the quality of information incentives. As such, we do not consider it appropriate at this time to propose any changes to these incentives for 2007/08.

3.44. **Our initial proposal is therefore to retain the quality of information incentives in their current form for 2007/08**. In terms of benchmarks, our initial proposal is that performance over the 12 months preceding 1 April 2007 represents the best comparator for performance over 2007/08. We also propose maintaining the same monetary value for the caps, collars and target for 2007/08, but applying these for 12 months from April 2007 (i.e. effectively halving the monetary value of these incentives to NGG over the duration of the incentive).

3.45. We intend to monitor NGG's performance with regard to these incentives over winter 2006/07, and assess in advance of our February consultation whether any revisions to the incentives are appropriate. We also commit to publishing performance data relating to NGG's demand forecasting and website delivery on a monthly basis through winter 2006/07 (as and when it comes available). We would encourage respondents to use this performance data to inform their responses to this document.

Income Adjusting Events

3.46. As noted in Chapter 2, most respondents to the October consultation supported the continuation of Income Adjusting Event (IAE) provisions. However, some expressed concern that a lack of transparency may make the assessment of proposed IAEs difficult.

3.47. We consider it essential that a consistent approach is taken towards IAE provisions in electricity and gas. **We therefore propose retaining the concept of IAEs for 2007/08**.

Internal SO incentive scheme

3.48. In our October consultation, we outlined our preliminary views on the scope and duration of the internal SO incentives scheme. In light of respondents' views, we propose no change to these views for our initial proposals. Therefore, the remainder of this section focuses on the key outstanding issues relating to the form of the internal SO incentive scheme. These are:

- proposed changes in NGG's internal incentivised costs,
- treatment of the roll forward of the RAV, and
- internal costs associated with future modifications to commercial frameworks.

NGG's internal incentivised costs

3.49. In our October consultation, we set out our proposed allowances for opex, capex and tax allowances for 2007-12. After further discussions with NGG we consider it appropriate to increase our capex allowance, tax and pensions allowance, however we do not propose making any further adjustments to the opex allowances.

3.50. Table 3.2 summarises our revised proposals for NGG's internal incentivised costs. Detailed revenue calculations are set out in Appendix 10. Note that our Initial Proposals set total allowed revenue over 2007/12 at £204.4 million.

Table 3.2: NGG Internal Incentivised Costs 2007-2012 (£ million, 2004/05 prices)

	NGG Forecast	Ofgem Initial Proposals	Change from Preliminary Views
Opex	126.4	122.1	no change
Capex	64.4	48.7	+7.2
Tax	n/a	3.4	-5.8
Pensions	n/a	34.4	+1.7

3.51. We have adjusted the level for capital expenditure for 2007/08 to 2011/12 by £7.2 million based on discussions with NGG regarding the proposed replacement of the Integrated Gas Management System (IGMS). Firstly, NGG revised its proposed profile of this project to phase the project evenly over 4 four years from 2010/11. In addition, we have reduced the costs of the overall project from £30 million to £27 million, as a more realistic estimate based on industry best practice.

3.52. The key remaining difference between our initial proposals and NGG's forecast is NGG's proposed capital expenditure for real time dynamic modelling of the NTS and separate training simulator facilities. NGG has forecast £14 million. We continue to believe that £5 million is a more realistic estimate based on comparable installations in the upstream and down stream oil and gas sector. We welcome respondents' views on this.

3.53. Following further discussions with NGG we have updated our tax and pension allowances as shown above.

Incentives and the roll forward of the RAV

3.54. As discussed in the electricity internal cost section in Chapter 2, the current internal incentive applies sharing factors to opex and incentivised capex that are aligned to those in the external incentive.

3.55. As with electricity, NGG has requested that similar consistency and certainty regarding the incentives on gas capital expenditure incurred and expenditure allowed into the RAV. Ofgem has proposed a similar incentive to that proposed by Ofgem for NGG's TO capital expenditure. As with electricity, the level of the sharing factor for NGG's TO capital expenditure is 25% for both over- and under-spend.

3.56. This proposal would entail similar changes to those proposed in Chapter 2 for electricity, namely:

- fixed sharing factors on capex over- and under-spend each year throughout the period of the internal incentive (with the remaining proportion of over- and under-spend being added to the RAV in each year), based on the TO incentive this would mean 75% of over-spends would be added to the RAV and 75% of under-spend would be deducted from the RAV, and
- not withstanding the above, a disallowance from the RAV of items of expenditure that are demonstrably inefficient or wasteful and an adjustment to clawback revenue recovered on such expenditure following a review of efficiency at the next Price Control Review.

3.57. With regard to the choice of sharing factors for internal operating expenditures, we invite respondents' views on whether it is appropriate to align them with the capex sharing factors or remain aligned to the external incentive scheme and whether the former would cause perverse incentives given the wide range of sharing factors associated with the external proposals.

NGG internal costs associated with future modifications to commercial frameworks

3.58. As with the electricity proposals outlined in Chapter 2, NGG has also raised the issue of incremental costs associated with modifications to commercial frameworks which are not represented in its Forecast Business Plan Questionnaire (FBPQ) submission and hence not included in proposed opex and capex allowances. NGG has proposed a similar process to that proposed for electricity which would provide appropriate remuneration for significant developments based on accountability to industry working groups and panels (rather than the existing IAE provision that has a threshold of £2million).

3.59. For gas, the relevant SO commercial frameworks covered would include:

- Uniform Network Code (UNC),
- System Management Principles Statement (SMPS), and
- Transmission Charging Methodology.

3.60. We invite comments from respondents as to whether NGG should be remunerated for costs related to such modifications by some alternative mechanism to the IAE provision.

4. Way forward

Chapter summary

This chapter briefly summarises our next steps.

Question box

There are no specific questions in this chapter.

4.1. Responses to this consultation document should be sent to wholesale.markets@ofgem.gov.uk to be received no later than **16 January 2007**. Further details of how to respond can be found in Appendix 1. In responding to this document please can you be clear whether your comments apply to the gas and/or electricity incentive schemes.

4.2. We will consider feedback we receive to this consultation, including that provided by NGET and NGG, in developing our final proposals and statutory licence consultation, with a view to agreeing SO incentive schemes with NGET and NGG to apply from 1 April 2007. When developing our final proposals we will also take account of the latest wholesale prices, and the effects of recent rule changes. We expect to publish our final proposals in February 2007.

4.3. If NGET and NGG consent to our final proposals, the incentive schemes would be effective from 1 April 2007. If either NGET or NGG do not accept our final proposals, we would have to decide whether to refer the matter to the Competition Commission, or to rely on our existing powers for the purposes of regulating NGET and/or NGG.

Appendices

Index

Appendix 1 - Consultation Response and Questions

1.1. Ofgem would like to hear the views of interested parties in relation to any of the issues set out in this document. We would especially welcome responses to the specific questions which we have set out at the beginning of each chapter heading and which are replicated below.

1.2. Responses should be received by **16 January 2007** and should be sent to:

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

1.3. 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.

1.4. 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.

1.5. Having considered responses to this initial proposals consultation, we intend to develop our final proposals and statutory licence consultation for SO incentive schemes to apply to NGET and NGG from 1 April 2007 that will then be consulted on in February 2007. Any questions on this document should, in the first instance, be directed to: Shelley Wenaas (project leader), Lisa Martin (electricity proposals) and Tim Dewhurst (gas proposals) Tel: 020 7901 7000, Email: wholesale.markets@ofgem.gov.uk

CHAPTER: One

There are no specific questions in this chapter.

Chapter Two

Question 1: What are your views on NGET's revised forecast of £458 million? In particular, do you consider that there are any areas where NGET is being risk disposed or risk averse in its assessment of costs? Alternatively do you consider that there are any drivers of cost that NGET has not identified?

Question 2: In this chapter we identify areas where we believe that NGET has over forecast its costs. Do you agree with our assessments? Please provide as much analytical detail as possible in your response.

Question 3: Within NGET's forecast a continued area of increasing cost is mandatory frequency response costs. What do you consider to be the drivers of costs for frequency response? What impact do you consider that CAP107 will have on these costs? Do you believe there is scope for cost reductions as competition is established in the provision of these services?

Question 4: NGET is forecasting that constraint costs will continue to be of the order of £81 million. Do you consider that there is any scope for reductions in these costs? In particular, do you consider that with falling wholesale gas prices there should be a reduction in within Scotland constraint costs?

Question 5: In November, a significant change was introduced to the electricity cash out arrangements (Modification P205). What is your assessment of the impact of this change on NGET's forecast level of costs? Please provide as much analytical detail as possible in your response.

Question 6: Do you think it is appropriate that we take into account the then current wholesale market conditions when setting the IBC target in the final proposals?

Question 7: What do you think is an appropriate level of IBC for 2007/08?

Question 8: Do you have any comments on our indexation analysis? Specifically, do you support the way in which indexation has been applied in the option we have proposed? Do you have any comments on our approaches to determining the adjustment factor? Are there any alternative approaches that we have not considered? Do you have any comments on the deadband size?

Question 9: What are your views on the four proposed options?

Question 10: Do you agree with our views on IAEs going forward?

Question 11: Do you have any comments on the draft Terms of Reference for a review of the external SO incentive scheme contained in Appendix 12?

Question 12: Do you agree with our Initial Proposals for levels of internal opex, capex, tax, and pensions allowances?

Question 13: What are your views on implementing fixed sharing factors for internal capital expenditures? If so do you have a view on the level of these sharing factors? What are your views on the alignment of the operating expenditure sharing factors?

Question 14: Do you think incremental internal costs associated with modifications to commercial frameworks (e.g. BSC) should be remunerated through the existing IAE provision or via a more automatic cost recovery process built around enhanced cost reporting and accountability to industry through the existing commercial frameworks?

CHAPTER: Three

Question 1: Do you agree with the proposed introduction of a new incentive to limit emissions of methane from the NTS from April 2007, and link this incentive to the prevailing price of carbon?

Question 2: Do you agree that the scope for all other components should remain the same as previous years for the external gas SO incentives?

Question 3: Do you agree with our proposal to vary the target for gas shrinkage on the basis of actual (2007/08) flows through St Fergus?

Question 4: Do you consider the proposed volumes for the shrinkage targets to be appropriate?

Question 5: Do you consider it is appropriate to retain the existing gas reference price methodology for the gas shrinkage incentive?

Question 6: Do you agree with our proposed target for gas reserve, and our intention to undertake a more fundamental review of this incentive in 2007?

Question 7: Do you agree with our proposal to review the reference prices that apply to the gas reserve incentive?

Question 8: Do you agree that, where market prices exceed reference prices for gas reserve, that the SO should pay these higher prices for OM gas?

Question 9: Do you agree with our initial proposals to retain the existing form of the residual gas balancing incentives?

Question 10: Do you have a view on the most appropriate form for the quality of information incentives in 2007/08? Do you consider these incentives should be revised in light of NGG's performance over winter 2007/08?

Question 11: Do you agree with our views on IAEs going forward?

Question 12: Do you agree with our Initial Proposals for internal costs?

Question 13: Do you agree that we should implement fixed sharing factors for internal capital expenditure? If so what should the level of the sharing factors be? Should the operating expenditure sharing factors be aligned with the capex factors, or aligned to the external incentive?

Question 14: Do you think incremental internal costs associated with modifications to commercial frameworks (e.g. UNC) should be remunerated through the existing IAE provision or via a more automatic cost recovery process built around enhanced cost reporting and accountability to industry through the existing commercial frameworks?

CHAPTER: Four

There are no specific questions in this chapter.

Appendix 2 – The Authority’s Powers and Duties

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

1.2. The Authority's powers and duties are largely provided for in statute, principally the Gas Act 1986, the Electricity Act 1989, the Utilities Act 2000, the Competition Act 1998, the Enterprise Act 2002 and the Energy Act 2004, as well as arising from directly effective European Community legislation. References to the Gas Act and the Electricity Act in this Appendix are to Part 1 of each of those Acts.[17]

1.3. Duties and functions relating to gas are set out in the Gas Act and those relating to electricity are set out in the Electricity Act. This Appendix must be read accordingly[18].

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

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

- The need to secure that, so far as it is economical to meet them, all reasonable demands in Great Britain for gas conveyed through pipes are met;
- The need to secure that all reasonable demands for electricity are met;
- The need to secure that licence holders are able to finance the activities which are the subject of obligations on them[19]; and
- The interests of individuals who are disabled or chronically sick, of pensionable age, with low incomes, or residing in rural areas.[20]

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

[17] Entitled “Gas Supply” and “Electricity Supply” respectively.
[18] 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.
[19] 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.
[20] The Authority may have regard to other descriptions of consumers.

- Promote efficiency and economy on the part of those licensed[21] under the relevant Act and the efficient use of gas conveyed through pipes and electricity conveyed by distribution systems or transmission systems;
- Protect the public from dangers arising from the conveyance of gas through pipes or the use of gas conveyed through pipes and from the generation, transmission, distribution or supply of electricity;
- Contribute to the achievement of sustainable development; and
- Secure a diverse and viable long-term energy supply.

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

- The effect on the environment of activities connected with the conveyance of gas through pipes or with the generation, transmission, distribution or supply of electricity;
- The principles under which regulatory activities should be transparent, accountable, proportionate, consistent and targeted only at cases in which action is needed and any other principles that appear to it to represent the best regulatory practice; and
- Certain statutory guidance on social and environmental matters issued by the Secretary of State.

1.8. The Authority has powers under the Competition Act to investigate suspected anti-competitive activity and take action for breaches of the prohibitions in the legislation in respect of the gas and electricity sectors in Great Britain and is a designated National Competition Authority under the EC Modernisation Regulation[22] 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.

[21] Or persons authorised by exemptions to carry on any activity.
[22] Council Regulation (EC) 1/2003

Appendix 3 - Glossary

B

Bid multiplier

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

Black Start

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

British Electricity Trading and Transmission Arrangements (BETTA)

The BETTA reforms, introduced on 01 April 2005, created a single, competitive wholesale electricity trading market in Great Britain. These trading arrangements are based upon the preceding England and Wales trading arrangements. The BETTA arrangements allow parties to trade energy forward through bilateral over the counter trades, through exchanges, or in any other manner they deem appropriate on a GB basis.

E

Electric compression

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

Enhanced reactive service

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

F

Fast reserve

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

Fast Start

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

Free Headroom

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

Frequency response

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

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 the scheme was agreed.

Intertrip

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

L

Linepack

The volume of gas within the NTS, analogous to short-term storage flexibility.

LNG

Liquefied Natural Gas.

M

Maxgen

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

N

NGET

National Grid Electricity Transmission plc (NGET) is the system operator (SO) for the electricity transmission system in Great Britain (GB), with responsibility for making sure that electricity supply and demand stay in balance and the system remains within safe technical and operating limits.

NGG

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

NTS

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

O

OCM

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

Offer multiplier

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

OM

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

OUG

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

R

Reactive Power

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

Regulatory Asset Value (RAV)

The value ascribed by Ofgem to the capital employed in the licensee's regulated transmission or (as the case may be) distribution business (the 'regulated asset base'). The RAV is calculated by summing an estimate of the initial market value of each licensee's regulated asset base (at privatisation) and all subsequent allowed additions to it at historical cost, and deducting annual depreciation amounts calculated in accordance with established regulatory methods. These vary between classes of licensee. A deduction is also made in certain cases to reflect the value realised from the disposal of assets comprised in the regulatory asset base. The RAV is indexed to RPI in order to allow for the effects of inflation on the licensee's capital stock. The revenues licensees are allowed to earn under their price controls include allowances for the regulatory depreciation and also for the return investors are estimated to require to provide the capital.

S

SAP

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

Sharing factors

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

Shipper

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

Shrinkage gas

Shrinkage gas is that which is lost or otherwise unaccounted for from the gas Transportation System.

Standing reserve

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

System Operator (SO)

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

U

UAG

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

UNC

Uniform Network Code

W

Warming

This service is used to decrease the notice period a unit needs to deliver power. It substantially increases the flexibility of plant on the system. Warming and hot standby contracts exist, in £/hr availability fees. When a warmed unit is instructed the warming payment falls away, but the hot standby fees remains (provided it has been initiated), provided for via bilateral agreement. Note that from 1 November 2006 Warming has been superseded by the BM start up service.

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:

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London
SW1P 3GE
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