

National Grid Electricity Transmission and National Grid Gas System Operator incentives from 1 April 2009

Document type: Final Proposals Consultation

Ref: 14/09

Date of publication: 27 February 2009

Deadline for response: 27 March 2009

Target audience: System Operators, Transmission and Transportation System Owners, Generators, Shippers, Suppliers, Customers and Other Interested Parties

Overview:

National Grid Electricity Transmission (NGET) is the System Operator (SO) for the electricity transmission system in Great Britain (GB), and National Grid Gas (NGG) is the SO for the gas transportation system in GB. This document sets out our final proposals for SO incentive schemes for NGET and NGG to apply from April 2009, including statutory licence modification consultations.

If NGET and NGG consent to our final proposals, and subject to responses to this consultation, the incentive schemes would be effective from 1 April 2009. If either NGET or NGG do not consent to the licence modifications, thereby not accepting our final proposals, we would have to decide whether to consult again on revised proposals, to refer the matter to the Competition Commission, or to rely on our existing powers for the purposes of regulating NGET and/or NGG.

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Context

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

Associated Documents

- National Grid Electricity System Operator Incentives: Final Proposals Report, National Grid, February 2009
- National Grid Gas (NTS) System Operator Incentives: Initial Proposals Consultation Report, National Grid, January 2009
- National Grid Electricity System Operator Incentives: Initial Proposals Consultation, National Grid, November 2008
- National Grid Gas (NTS) SO Incentives for 1 April 2009: Initial Proposals Consultation, National Grid, November 2008

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Summary

In this document we set out our final proposals for the electricity and gas transmission System Operator schemes for National Grid Electricity Transmission (NGET) and National Grid Gas (NGG) to apply from 1 April 2009. We consider that our final proposals represent a fair balance of risk and reward between National Grid and its customers.

Ofgem's Final Electricity SO Proposals

In November 2008, NGET provided its initial forecast for 2009/10 incentivised balancing costs of £991m. Following discussions with Ofgem and consideration of respondents' views, NGET has subsequently revised this forecast to £813m. NGET has also proposed an amendment to the calculation of the Net Imbalance Adjustment (NIA)¹ which adjusts its current forecast to £615m. NGET has also proposed that for two possible elements of its costs the target should be adjusted downwards if these costs do not arise as expected. As a result of our analysis, we consider that there remains sufficient uncertainty in NGET's forecast costs to warrant the inclusion of a deadband in the incentive scheme target of ±£15m.

NGET proposed a number of different electricity scheme options including separation and indexation of reactive power costs and a separate scheme for transmission losses. However, we feel that we have not seen convincing evidence to support a significant change to the form of the incentive mechanism. Further, based on responses to NGET's consultation, no consensus has formed in the industry as to the most appropriate scheme option. Given our view of NGET's forecast costs, we propose a scheme with a deadband between £600m and 630m. The parameters of our final proposal are set out below.

IBC Target	Upside (reward to NGET if costs are below target)		Downside (payment by NGET if costs are above target)	
£m	Sharing factor (%)	Cap (£m)	Sharing factor (%)	Floor (£m)
600-630	25	15	15	15

Ofgem's Final Gas SO Proposals

With respect to gas, following consideration of the views of respondents to NGG's consultation on its proposals for its gas SO incentive scheme and further discussions with NGG, we have developed a set of proposals which we believe offer a number of improvements over previous years' schemes. These proposals include a number of key changes which will enhance the incentives on NGG regarding its behaviour in the market and increase incentives to make efficiency savings. We believe these proposals, which are

¹ This enables the costs for which NGET is incentivised to vary due to changes in the wholesale electricity price and system length.

the result of significant work throughout the year by NGG, industry and Ofgem, represent a fair balance of risk and reward to NGG and customers.

The main proposed changes to the current incentive schemes are:

Shrinkage scheme: Significant improvements to NGG's forecast model of volumes; changes to the duration of the shrinkage incentive scheme from one year to three years to allow NGG to make efficiency savings over a longer period; and improvements to parts of the gas and electricity reference price methodologies.

Residual balancing scheme: In response to views expressed by industry a sharper incentive on NGG to minimise the number of trades it makes on the commodity market and where it does trade to do so as close to the marginal trade as possible; removal of the incentive on NGG to resolve small variances in linepack (again in response to industry views that NGG should minimise its intervention in the market); and changes to the scheme parameters such that NGG has to improve its performance under this incentive to achieve the same return as this year.

Demand forecasting: A tightening of the current target for demand forecasting accuracy from 3.5% to 3.0%.

Methane incentive: A reduction in the target on emissions from venting compressors for 2009/10, to include venting from electric drive compressors within this target and to reflect the value of minimising all pollutants rather than just methane.

Unaccounted for Gas (UAG): The development of a new three year incentive on NGG to reduce gross UAG volumes.

Operating Margins (OM): As a result of the uncertainty regarding the provision of OM we are proposing to only incentivise NGG on the utilisation costs of OM and to allow it to pass through the holding costs.

Next Steps

Subject to responses to this consultation, if NGET and NGG consent to these final proposals the licence modifications would be effective from 1 April 2009. If NGET and/or NGG do not consent, we will have to decide whether to consult again on revised proposals, to refer the matter to the Competition Commission, or rely on direct regulation of NGET's and/or NGG's SO costs based on our existing powers.

Although we consider that these final proposals represent a significant development in some areas of SO incentives there are a number of areas where considerable further work should be undertaken to establish a solid basis in order for longer term incentives to be developed. We will therefore actively engage with National Grid and market participants in this process from 1 April 2009.

1. Introduction

Chapter Summary

This chapter provides a short background on the process so far. It also provides an outline of the structure of this document and the way forward.

Question box

There are no specific questions in this chapter.

Background

1.1. National Grid Electricity Transmission (NGET), a subsidiary of National Grid plc, is the system operator (SO) for the high voltage electricity transmission system in Great Britain (GB), with responsibility for making sure that electricity supply and demand stay in balance and the system remains within safe technical and operating limits².

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

1.3. In addition to their licence requirements we also look to incentivise NGET and NGG financially to operate the gas and electricity systems in the most economic and efficient manner.

Process

Summer workshops and consultations

1.4. This year we again requested that NGET and NGG (National Grid)³ provided and consulted upon its own set of proposals. In response to concerns expressed by participants during the process for agreeing last year's consultation scheme we asked NGET and NGG to begin their consultation phase earlier in the year to enable a higher

² NGET is also the owner of the high voltage electricity transmission network in England and Wales, whilst in Scotland the transmission network is owned by Scottish and Southern Energy and Scottish Power.

³ Where we refer to specific proposals relating to electricity and gas we refer to NGET and NGG as appropriate. In combination we will refer to National Grid.

level of engagement with interested parties. In response to this, NGET and NGG held workshops on 26 June 2008 and 25 June 2008 respectively in which they sought to obtain views from the industry regarding the elements of the scheme that should be revised. Following the workshop, during the summer NGET issued a mini consultation on indexation⁴ and NGG issued mini consultation papers on shrinkage and residual balancing⁵ and operating margins⁶.

1.5. On 27 November 2008, NGET published its Initial Proposals Consultation, to which it received seven responses. NGET also held a series of one-to-one meetings with interested parties and held a workshop on 16 December. NGET has also published its Final Proposals Report.

1.6. Following consideration of responses to these earlier consultations and views expressed at the June workshop, on 12 November 2008, NGG published its Initial Proposals Consultation, to which it received six responses. NGG also held a series of one-to-one meetings with interested parties and held a workshop on 28 November 2008. NGG published its Initial Proposals Consultation Report on 12 January 2009, which provided its revised initial proposals following consideration of respondents' views.

1.7. We have scrutinised NGET's and NGG's forecasts for their respective incentivised SO costs; considered the responses to their Initial Proposals consultations and the views expressed at the Workshops along with NGG's and NGET's consultation reports. In the course of scrutinising the forecasts, we have also received further information from and held detailed discussions with NGET and NGG and held bilateral discussions with other interested parties. All of this information has helped us to develop our final proposals for the SO incentive schemes to apply to NGET's and NGG's external SO costs from 1 April 2009, which are discussed in this document⁷.

Structure of this document

1.8. This final proposals document consists of three chapters:

⁴ "Consultation on the Development of an Incentive Target Indexation Methodology", National Grid, September 2008.

⁵ "NGG (NTS) - Consultation on Shrinkage and Residual Balancing Incentive Issues", National Grid, August 2008.

⁶ "NGG (NTS) - Conclusions on Operating Margins Contestability and Initial Thoughts for Associated SO Incentive Arrangements", National Grid, September 2008.

⁷ NGET and NGG currently have incentive schemes in place which relate to their internal SO costs, these schemes run until March 2012. When they were set it was agreed that Operating Costs would continue to be subject to the same sharing factors used in the external incentive scheme. Therefore our proposed licence modifications include this proposal. The current incentive schemes for external costs expire on 31 March 2009.

- Chapter one: provides the background to our proposals, outlines the process we are following in developing SO incentive schemes for NGET and NGG from 1 April 2009, and sets out the structure of the document and the way forward;
- Chapter two discusses our final proposals for the electricity SO incentive scheme to apply to NGET's external SO costs⁸ from 1 April 2009; and
- Chapter three discusses our final proposals for the gas SO incentive schemes to apply to NGG's external SO costs from 1 April 2009.

1.9. In both chapters two and three, we explain how our final proposals have been informed by NGET's and NGG's initial proposals, the views of market participants and the additional information provided by NGET and NGG.

Way forward

1.10. Appendix two of this document contains a statutory notice of our proposal to modify by agreement NGET's electricity transmission licence under section 11 of the Electricity Act 1989. Appendix three of this document contains a statutory notice of our proposal to modify by agreement NGG's gas transporter licence under section 23 of the Gas Act 1986⁹. These statutory modification notices propose to implement the proposals set out in this document (subject to responses to this consultation).

1.11. We would welcome the views of interested parties on all aspects of our proposed modifications. Responses should be sent to gb.markets@ofgem.gov.uk, to be received no later than 27 March 2009. Further details of how to respond can be found in Appendix one.

1.12. The statutory notices under section 11 of the Electricity Act 1989 and section 23 of the Gas Act 1986 specify a period of not less than 28 days during which interested parties can make representations or objections to the proposed licence modifications, and during which the Secretary of State may direct the Gas and Electricity Markets Authority (the Authority) not to make the proposed modifications. Following any such representations, objections or direction, the Authority may make such revisions to the proposed licence modifications as it considers appropriate and carry out a further statutory consultation on the new proposed licence modifications.

1.13. NGET and NGG must consent to the proposed licence modifications to their respective licences before they can be implemented. If NGET and/or NGG do not consent to the proposed licence modifications Ofgem can refer the proposed SO incentive scheme modifications to the Competition Commission for final adjudication. Alternatively, we could allow the incentive schemes to fall away. If this occurs, NGET and/or NGG will

⁸ As noted earlier, the sharing factors for which will also be applicable to the Operating Costs component of the internal incentive scheme.

⁹ It should be noted that we have redrafted Special Condition C8F completely and propose to replace the condition in full.

simply pass through the actual costs of operating the system to parties using the respective system. Ofgem would continue to monitor the performance of NGET and/or NGG as SO under the relevant licence conditions and could take enforcement action and impose financial penalties if NGET and/or NGG were not operating their respective system in an efficient, economic or co-ordinated manner, or were found to be in breach of other relevant licence conditions or other relevant statutory requirements.

1.14. If NGET and NGG consent to the proposed licence modifications, Ofgem intends, subject to any representations made during the consultation and any direction received from the Secretary of State, to direct the relevant modifications to NGET's transmission licence and NGG's transportation licence in line with the proposed licence modifications shortly after 27 March 2009, so that the new licence conditions would apply on and from 1 April 2009.

Way forward - longer term

1.15. We consider that our final proposals this year (building on the work carried out by National Grid during the course of the consultation period) represent a significant improvement over previous years in some areas. We consider that these changes will establish a solid basis for longer term schemes to be developed (our final proposals would already provide longer term incentives for some elements of the gas scheme).

1.16. There are a number of areas where considerable further work needs to be undertaken to pave the way for a longer term scheme. These include ensuring that the incentive schemes take account of work carried out in other related workstreams, for example the Transmission Access Review. We will therefore engage with National Grid and market participants to take this work forward from 1 April 2009. In this document we outline, where possible, the areas of work that we consider should be taken forward.

2. Electricity external costs incentive scheme from April 2009

Chapter Summary

This chapter outlines the forecasts provided to us by NGET on electricity external SO costs for 2009/10 and NGET's initial proposals based on those forecasts, our views on NGET's forecasts and initial proposals following consideration of the views of respondents to NGET's consultation and our final proposals for an electricity external SO incentive scheme to apply from 1 April 2009.

Question box

Question 1: Do you consider that the final proposals for the SO incentive scheme to apply to NGET's external SO costs represent a fair balance of risk and reward?

Question 2: Do you consider that the proposed licence modifications appropriately reflect the final proposals as described in this chapter?

Background

2.1. Since the introduction of the New Electricity Trading Arrangements (NETA) in 2001 the electricity system operator incentive schemes that have been in place have taken the form of a single target on the Incentivised Balancing Cost (IBC) with linear sharing factors, a cap and a floor. The incentive schemes for each year along with outturn payments to/from NGET and baseload electricity prices are shown in Table 2.1.

Table 2.1 Historical External SO Incentive Schemes^{10,11,12}

£ m	Target	Sharing factors		Cap	Floor	Actual	Payment to/from NGET	Outturn Baseload Prices (£/MWh)
		Upside (%)	Downside (%)					
2001/02	382	40	12	46.3	-15.4	263.0	46.3	17.8
2002/03	367	60	50	60	-45	285.6	48.6	16.3
2003/04	340	50	50	40	-40	280.8	32.2	19.7
2004/05	320	40	40	40	-40	289.2	12.2	23.8
2005/06	378	40	20	40	-20	427.2	-4.0	42.4
2006/07	No scheme agreed					495.0	-	32.3
2007/08	430-445	20	20	10	10	451	-1.2	40.4
2008/09	530-545	25	25	15	15	770 ¹³	-15 ¹³	78 ¹³

2.2. In 2006/07 NGET and Ofgem did not agree on an IBC target. As it is entitled to do under the terms of its licence, NGET did not consent to our proposed incentive schemes. At that time, Ofgem chose to continue to exercise its power to monitor this aspect of NGET's activities, rather than refer the matter to the Competition Commission.

2.3. Under the current incentive scheme there is a 'deadband' between £530m and £545m outside of which NGET is exposed to 25% of any difference in balancing costs up to a maximum of £15m.

Forecast costs for 2008/09

2.4. NGET's forecast for 2008/09 incentivised balancing costs outturn is between approximately £750m and £810m compared with a target of £530m to £545m. At the time of its Initial Proposals Consultation its forecast was £770m - its most recent forecast is approximately £800m. As such it is expected that the incentive target floor will be hit with a cost to NGET of £15 million.

2.5. NGET has suggested that the increase in the costs this year have been as a result of:

- increased wholesale power prices (the forecast power price was £56/MWh against an average expected outturn of £78/MWh)¹⁴;
- a reduction in system length (with April 08 being the shortest month on record)¹⁴;
- a reduction in the availability of free headroom;

¹⁰ Targets and actual IBC before 2005/06 have been recalculated to include net transmission losses.

¹¹ All data in money of the day.

¹² The figures which appear in this table are all based on the existing NIA calculation.

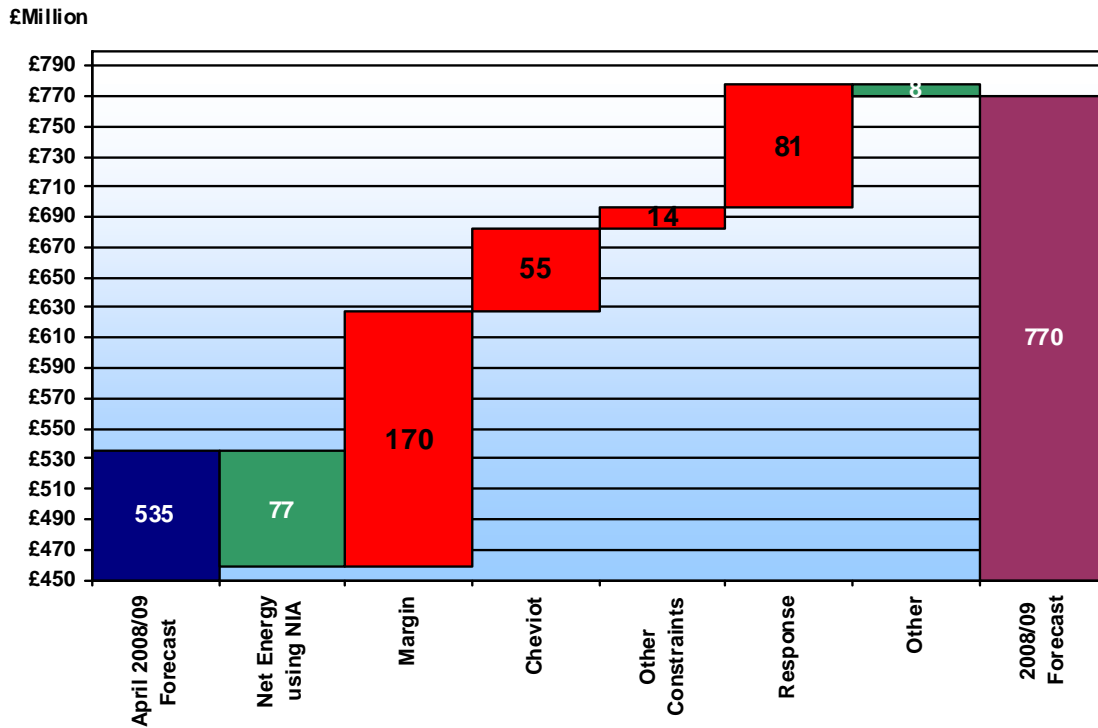
¹³ Based on forecast as per NGET's initial proposals consultation.

¹⁴ NGET has suggested that there are problems with the current NIA calculation such that these changes are not sufficiently accounted for when adjusting for these factors.

- a change in service providers; and
- an increase in constraint costs and volume.

2.6. Figure 2.1 shows the cost increases seen in 2008/09 by components.¹⁵

Figure 2.1: 2008/09 cost increases by components



Constraint costs

2.7. Constraint costs rose significantly during 2008/09 from the forecasted £124m to an expected outturn of £194m (in relation to the overall forecast of £770m). NGET attributed this to a 25% increase in the number of circuit outage days affecting the Cheviot constraint and higher costs of resolving constraints resulting from increases in the bid/offer spread. NGET’s most recent forecast is £238m (in relation to the overall forecast of £800m).

¹⁵ This illustration is based on the forecast included in NGET’s initial proposals consultation.

Implications for 2009/10

2.8. The background of significant balancing cost increases this year and the lack of certainty as to the key drivers behind elements of these increases (particularly reduced system length, reduction in free headroom and constraint costs) and hence as to whether these are likely to affect costs next year has presented significant challenges to Ofgem when developing our final proposals for NGET's incentive scheme for 2009/10.

2.9. Despite this, however, we consider that the consultation process carried out by NGET, industry engagement in this process and considerable analysis carried out by Ofgem has enabled us to develop final proposals for a scheme which we consider represents a fair balance of risk and reward between NGET and consumers.

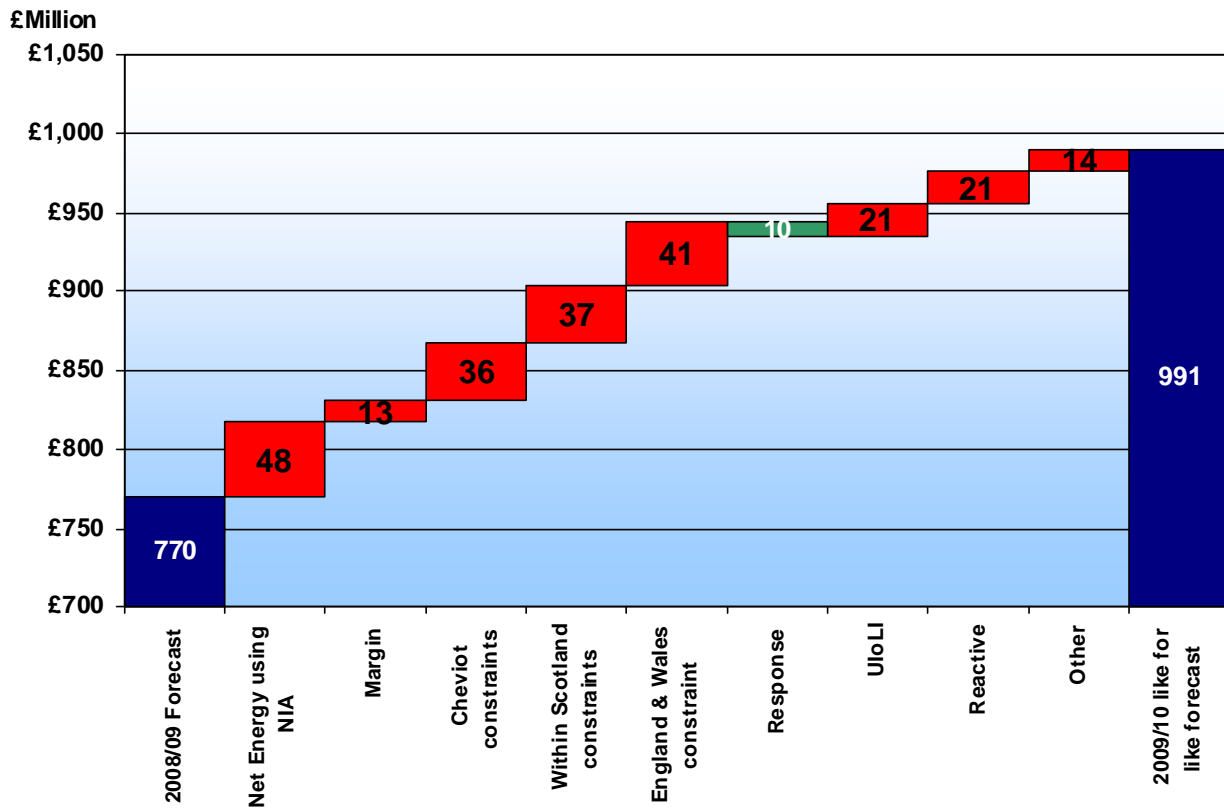
Forecast costs for 2009/10

NGET's initial proposals

2.10. In its initial proposals document, NGET set out its central forecast (on a like for like basis to preceding years) for 2009/10 as £991m.

2.11. The waterfall diagram at Figure 2.2 shows the cost increases from the 2008/09 expected outturn of £770m to NGET's initial proposals forecast of £991m for 2009/10 by components.

Figure 2.2: Cost increases from 2008/09 forecast outturn of £770m to NGET’s November 2008 initial proposals forecast for 2009/10 IBC costs



2.12. Figure 2.2 includes £21m of costs defined as Use it or Lose It (UIoLI). NGET forecast these costs as resulting from a change in the operation of the Anglo-French Interconnector (IFA) which NGET believed would change the way in which it can use the IFA for provision of balancing services.

Respondents’ views

2.13. In general, respondents were broadly comfortable that NGET had identified the cost drivers that affect its SO costs and that the assumptions seemed broadly sensible. However, some respondents pointed out that:

- The fuel and power prices used in the forecast were too high;
- That 2008/09 had been an exceptional year and therefore using costs and market behaviour seen in this year as a baseline may not have been appropriate;
- The forecast did not take account of expected reductions to demand resulting from the economic climate; and
- The constraints element of the forecast should not incorporate a premium for Scottish constraint bid prices given the action being taken to mitigate these costs.

2.14. The majority of respondents considered that the risk and costs associated with the change of use of the IFA were too uncertain to predict. One respondent considered that if this did lead to additional costs NGET should seek to address this via an Income Adjusting Event (IAE).

NGET's January 2009 revised forecast

2.15. In January 2009 NGET provided Ofgem with a revised forecast for its Incentivised Balancing Costs (IBC) for 2009/10 of £878m based on the most recent data available. This forecast took into account changes to wholesale prices, demand patterns and to some extent relied less heavily on information from 2008/09 (particularly with regard to market length).

2.16. The January forecast also took into account the most recent information available regarding outage planning which reduced its forecast of constraint costs down to £262m. It further took into account discussions between NGET and Ofgem regarding the key drivers of these costs. These forecast costs are shown against NGET's most recent forecast outturn costs for 2008/09 in Table 2.2.

Table 2.2: January 2009 forecast constraint costs by area against the expected outturn costs for 2008/09

Year	Cheviot	Scotland	England	Total
Latest 2008/09 forecast	£153m	£57m	£28m	£238m
2009/10	£142m	£69m	£51m	£262m

2.17. When providing its January 2009 forecast, NGET identified the main cost drivers for the forecast increases for 2009/10 as:

- an increase in the volume of outages (a number of these being construction outages across critical constraint boundaries to connect new generators);
- an increase in outages occurring after the October clock change, implying higher replacement costs; and
- 800MW of new wind generation, a significant proportion of which is located in North Scotland.

Ofgem's views on NGET's January forecast

2.18. Ofgem considered that the revised forecast put forward by NGET largely took into account changes to the target driven by more recent data as well as information regarding revisions to the wholesale prices, the most recent outage programme and expected demand. However, we continued to have concerns (in agreement with some respondents to NGET's consultation) that this revised forecast still relied too heavily on information

from 2008/09 which we were not convinced was an appropriate basis for the forecasts for 2009/10.

2.19. After analysing this reforecast we still considered that a significant amount of these costs had not at that stage been justified by NGET. In particular we had concerns that:

- Operating Reserve costs: NGET had based its forecast of the price at which generators offer reserve volumes to it by comparing the ratio of historic offer prices to relevant wholesale prices (the so-called “multipliers”). We believe that NGET’s forecast of these multipliers (particularly for CCGTs and coal plant) was too high resulting in significant additional costs;
- Operating Reserve and Frequency Response volumes: NGET had forecast levels of Operating Reserve and Frequency Response volumes that were based on patterns seen in 2008/09. As with respondents to the consultation we considered there was uncertainty as to whether the information from 2008/09 was “exceptional” or whether these patterns were likely to continue into 2009/10;
- UIoLI (changes in rules on the IFA): We recognised the changes in these rules may lead to changes in the way in which NGET can use the IFA. However, we agreed with respondents that there was significant uncertainty with regards to this risk and the associated costs;
- General increase in contract costs: NGET had included increases in its contracts for a number of balancing services. Although we recognise that there has been increases in contract costs, we considered that the increases suggested by NGET were higher than should be expected; and
- Unclassified BM: This relates to costs that NGET incurs, but that it cannot put into a specific category. We did not consider that NGET had fully justified all of the increases in costs that it has forecast.

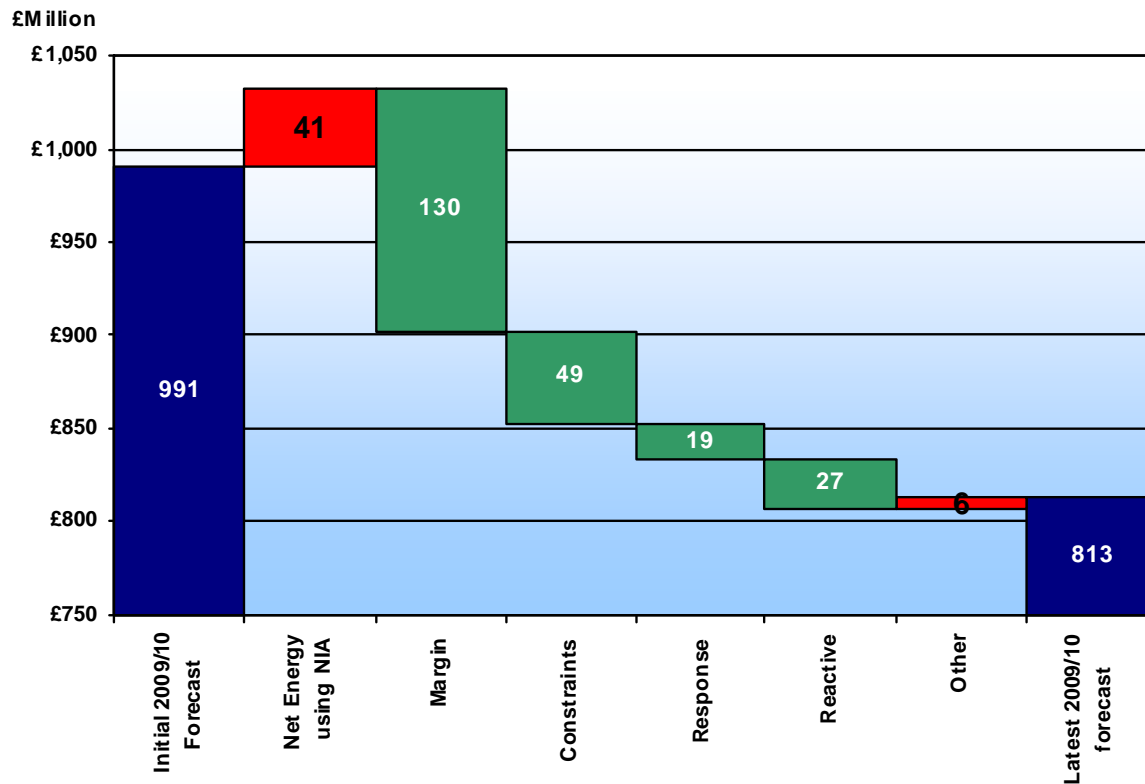
Constraint costs

2.20. Ofgem considered that there continued to be significant uncertainty regarding constraint costs for 2009/10. However, we are aware of the work being undertaken with respect to mitigating these costs in other forums and consider that the outcome of these forums should feed into the incentive scheme. We discuss our final proposals with respect to constraint costs below.

NGET’s February forecast

2.21. Following detailed discussions with Ofgem regarding our concerns outlined above, NGET provided Ofgem with a subsequent revised forecast on 9 February 2009 of £813m which resolved a number of our concerns. NGET has since published its Final Consultation Report which also includes this number as its final forecast. Figure 2.2 summarises the main changes from NGET’s initial proposals forecast of £991m to its latest February forecast of £813m.

Figure 2.2 Cost decreases from NGET’s November 2008 initial proposals forecast for 2009/10 IBC costs to its February forecast of these costs



2.22. In comparison with the £878m January 2009 forecast, the February forecast included:

- A review of the Operating Reserve fuel type multipliers to take into account the analysis carried out by Ofgem which reduced the January 2009 forecast (by £25m);
- A corresponding change to constraint costs to take into account changes in the Operating Reserve multipliers (by £4m); and
- A reduction in Frequency Response and Short Term Operating Reserve costs to take into account most recent outturn data (by £25m).

Proposed automatic adjusters

2.23. NGET has considered the views regarding UIoLI of both respondents to its initial proposals consultation and Ofgem. It has accepted that there is significant uncertainty regarding this risk. NGET has therefore proposed the inclusion of an automatic adjuster which would enable the Authority to **reduce** the target in the event that there are material changes to NGET’s assumptions regarding the provision of certain balancing services. NGET envisaged that this mechanism would cover both use of the IFA and changes in their expectation of the availability of certain commercial ancillary service providers. The triggers for these adjustments would be agreed bilaterally between the

Authority and NGET and if met the triggers could reduce NGET's target (and accompanying scheme parameters).

Ofgem's views

2.24. Having reviewed the revised forecast sent through by NGET, Ofgem is now satisfied that (given the automatic downward adjusters) the proposed forecast of £813m is a balanced view of anticipated costs for 2009/10.

Automatic adjusters

2.25. We also agree that the use of an automatic downward target adjuster in the event that there is a material change to NGET's assumptions regarding the availability of balancing services is a sensible method of dealing with the UIoLI IFA issue and other changes to the availability of commercial ancillary services providers.

Constraint costs

2.26. Ofgem considers that NGET's proposed forecast for constraint costs for 2009/10 is reasonable given the current market arrangements. However, on 17 February 2009¹⁶, Stuart Cook, Ofgem's Director of Transmission wrote to Alison Kay, National Grid's Commercial Director. In that letter NGET was asked to conduct an urgent review to consider (and if appropriate consult on) whether urgent changes to the existing commercial and charging arrangements were necessary before the start of the next charging year (starting 1 April 2009) to more effectively manage the costs of constraints, and to ensure that any constraint costs are recovered on an equitable basis from customers, suppliers and generators. The letter stated that the review should seek to address matters including options for reducing the level of constraint costs (both volumes and prices)¹⁷.

2.27. Ofgem is aware that the implementation of any measures arising from this review could have a significant impact on the constraint costs that NGET incurs. Although we consider it appropriate to include NGET's proposed forecast for these costs within the target, in the event that there are material changes to the market arrangements governing these costs we would be seeking to ensure that this is recognised within the incentive structure. The mechanism for delivering this will depend on the timing and scale of any changes but may involve Ofgem conducting a statutory consultation exercise on a revision to the incentive target and associated scheme parameters to take account of

¹⁶ The letter is available from the Ofgem website www.ofgem.gov.uk

¹⁷ In this letter Ofgem referred to NGET's Electricity Act 1989 obligation to develop and maintain an efficient, co-ordinated and economical system of electricity transmission (s9(2) of the Electricity Act) and its licence obligation as SO to co-ordinate and direct the flow of energy in an efficient, economic and co-ordinated manner (Standard Licence Condition C16 para 1).

these changes. Alternatively, it may be more appropriate for this to be achieved via an IAE and in this event Ofgem would expect NGET to raise an IAE in order to adjust its target downwards. Ofgem would be looking to the industry to inform its proposals or decisions in either of these cases. Ofgem will take a view (if appropriate following discussions with NGET and other interested parties) as to which option is more appropriate as soon as we have a clearer understanding of the nature and scope of the proposed changes to the commercial and charging arrangements. As it is highly unlikely that any changes can be made in readiness for the start of the charging year (April 2009) it is intended that if necessary any changes would be applied retrospectively to the date on which the new arrangements were introduced as well as prospectively.

Indexation Options: New NIA and Reactive Power

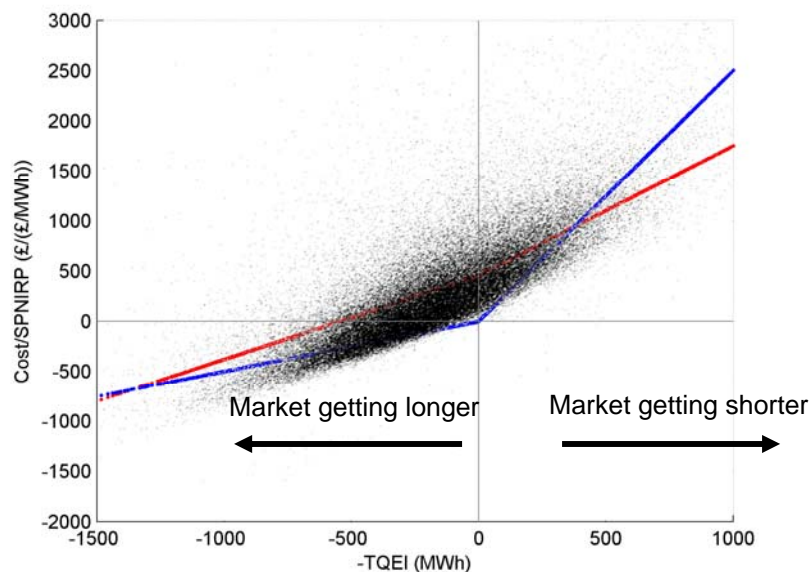
2.28. In our final proposals consultation for 2008/09, Ofgem asked NGET to take forward work to develop a method for indexing its incentivised balancing costs against external factors. Included in this work, we asked NGET to consider whether the current Net Imbalance Adjustment (NIA) calculation, which is intended to remove the effect of participants' imbalance from the incentive target, remains robust.

NGET's initial proposals

New NIA

2.29. During the development of its initial proposals, NGET has carried out significant analysis of the three way relationship between system length, wholesale prices and energy related balancing costs. Following this analysis it has developed a proposal for a revised NIA to replace the old NIA adjuster. Figure 2.3 shows the relationship between balancing cost, system length (Total Quantity of Energy Imbalance (TOEI)) and a wholesale price. The red line represents the new NIA NGET put forward in its Initial Proposals document; the blue line represents the NIA used in the existing scheme. As can be seen the blue line under adjusts when the system is in balance which does not reflect the fact that costs are still incurred when the system is in balance.

Figure 2.3 The relationship between balancing cost, system length and a wholesale price with NGET's proposed new NIA index



Reactive Power

2.30. NGET also proposed indexing Reactive Power costs to wholesale price as there is significant correlation between these two factors.

Respondents' views

New NIA

2.31. Six of the seven respondents supported the proposal to adopt NGET's proposed new NIA, though three qualified this support. It was suggested that it was appropriate to neutralise the impact of market length and power price volatility, and that old NIA over-rewarded the SO when the market was short and under-rewarded it when the market was long. One respondent queried whether or not NGET had used the best fit available to model its new NIA.

Reactive Power

2.32. The majority of respondents supported indexation of Reactive Power costs to wholesale prices. However, other respondents were not convinced of the reliability of the relationship between the two costs.

NGET's February proposals

2.33. Following consideration of respondents' views and discussions with Ofgem, NGET continued to propose the inclusion of the new NIA index and to index Reactive Power costs to wholesale price.

Ofgem's views

New NIA

2.34. We have carried out a significant amount of analysis of the proposed new NIA put forward by NGET. Although we think there are limitations to the new NIA, we are satisfied that it is a significant improvement on the current NIA.

2.35. In particular we agreed with respondents that at first sight the new NIA line did not look to be the best fit of the data. We have looked at ways of fitting the data better, including whether a "two kinked line" would improve the relationship. Despite this analysis, we have yet to find a line which is a significant improvement on NGET's proposal consistently across the data set, particularly when taking into consideration the increased complexity that would result from developing such a relationship. Having studied the data put forward by NGET and carried out statistical analysis of this fit we have concluded that for a "one kinked line" it is the best fit of the data.

2.36. We have also looked in detail at NGET's proposal, particularly as to whether new NIA may overcompensate NGET for changes to market length and power price, and have not found significant concern. We therefore propose that NGET's new NIA is implemented for 2009/10.

2.37. However, in the longer term, including taking into account the experience with the new NIA, we consider that improvements could be made. We will be asking NGET to see if a better adjuster can be found and intend to undertake further analysis on this.

Reactive Power

2.38. We have given consideration to NGET's proposals to index the Reactive Power costs against wholesale price. Although we agree in principle that these costs should be indexed against wholesale price, we consider that NGET has not fully demonstrated the reliability of the index. In addition, given recent change to RPI we are concerned that indexing these costs to wholesale price and not RPI could affect the incentive.

2.39. Our final proposal is therefore not to include an index for Reactive Power costs within this year's scheme. However, we will be asking NGET to carry out more analysis and detailed work in this area as part of developing a proposal to be included in the scheme to run from April 2010.

Unbundling

Transmission Losses

2.40. The current SO scheme includes an incentive on NGET to minimise transmission losses by combining a volume target with a reference price. The reference price is based on the average forward price plus an adjustment to replicate the shadow price of carbon.

The reference price is multiplied by the difference between the actual and target volume of losses to calculate a total financial value of transmission losses.

NGET’s initial proposals

2.41. NGET argues that it only has a limited amount of control over transmission losses. It currently forecasts that these losses will amount to 5.9 TWh in 2008/09. Because of its perception of limited control, NGET is proposing that both a deadband and low sharing factors be applied to a separate transmission loss incentive in 2009/10. Its proposals for a separate scheme for transmission are shown in Table 2.3.

Table 2.3: NGET’s proposals for an unbundled transmission losses scheme

Scheme	Target	Upside sharing factor	Cap, £m	Downside sharing factor	Floor
Unbundled transmission losses	5.8TWh – 6.2TWh	10%	£1m	10%	£1m

2.42. In addition to proposing unbundling transmission losses from the remainder of the incentive scheme, NGET additionally set out options that could see the incentive set for one, two or three years. The target, sharing factor, cap and floor would remain unchanged regardless of the duration the incentive was in place.

2.43. For 2009/10 in its initial proposals NGET put forward an average forward price of £63.26/MWh and an indicative shadow price of carbon of £9/MWh which together give a reference price of £72.26/MWh.

Reactive Power

2.44. In its initial proposals document, NGET proposed to unbundle Reactive Power into a separate incentive. Its proposals for a separate scheme for Reactive Power are shown in Table 2.4.

Table 2.4: NGET’s proposals for an unbundled Reactive Power scheme

Scheme	Initial Target	Upside sharing factor	Cap, £m	Downside sharing factor	Floor
Unbundled Reactive	£83m	30%	£4m	30%	£4m

Respondents’ views

2.45. Three respondents were in favour of unbundling reactive power and three were against. One supporter suggested that unbundling would help to facilitate a multi-year incentive, and another that NGET has significant control over volumes of reactive energy

procured. One detractor suggested that uncertainties on interactions with the SO's other costs could leave NGET with perverse incentives if this component were unbundled.

2.46. Five respondents opposed the unbundling of transmission losses from the main scheme. Several of these suggested that NGET has limited influence over transmission losses volumes, with one suggesting that it should be omitted from the incentive scheme altogether. One respondent reiterated the concern it had expressed on other unbundling options that these could create perverse incentives on the SO, due to the potential for overlaps in the different parts of the incentive scheme. One respondent did support unbundling transmission losses, on the grounds that this would facilitate the setting of a multi-year target.

NGET's February proposals

2.47. When submitting its consultation report in February 2009, it continued to propose the inclusion of separate incentive schemes for both Reactive Power and Transmission Losses. It proposed a reduced Transmission Losses Reference Price of £55/MWh, which we understand to be composed of a forward price of £48/MWh and an indicative shadow price of carbon of £7/MWh.

Ofgem's views

2.48. We agree with the majority of respondents that NGET has not demonstrated the case for unbundling the Transmission Losses or Reactive Power components of the incentive scheme. Although we accept that these costs are discrete from other components and therefore in theory could be unbundled, we are not convinced of the benefits of doing so.

2.49. We do however consider that this is something that NGET should continue to look at with respect to developing a scheme to apply from April 2010.

Scheme options for 2009/10

NGET's initial proposals

2.50. NGET proposed a menu of scheme options intended to allow participants to choose the level of risk and reward that they feel it is appropriate for NGET to be exposed to. The first three options are based on a bundled scheme with the new NIA mechanism discussed above, whereas option four includes a Reactive Power index which could add on to any of the schemes outlined in the first three options. Options five to eight look at separating Reactive Power and/or Transmission Losses into standalone incentive schemes. The options included schemes incorporating variable sharing factors (where the risk/gain to NGET decreased the further away from the target the costs outturned) and linear sharing factors with fixed caps and collars. There was also an option for the scheme to be broken down into quarterly or monthly targets to try to ensure that NGET remained incentivised during the whole incentive period.

Respondents' views

Sharing factors

2.51. With respect to sharing factors, three respondents supported variable sharing factors to reflect the asymmetric risk incurred by NGET. One of these respondents considered that the sharing factors should be inverted from those proposed by NGET so that NGET's share of the downside/upside increased the further away from the target that the costs outturned. Two respondents continued to support linear sharing factors as they considered that these were both simpler and better reflected the difficulties in ensuring the accuracy of the central target.

Caps and floors

2.52. One respondent suggested that the caps and floors should be set as a percentage of the outturn balancing costs rather than being fixed.

Quarterly/monthly scheme

2.53. The majority of respondents considered that a reduction in the incentive period would have limited benefit. Reasons cited for this view included that shorter periods would have a dilatory effect on the strength of incentives and that within-year volatility may make shorter targets harder to predict and administer.

NGET's February proposals

Unbundling

2.54. In its February 2009 report, NGET, having considered respondents' views, proposed three separate incentives for Transmission Losses; Reactive Power and the remaining bundled scheme.

Sharing factors/caps and floors

2.55. With respect to the Transmission Losses and Reactive Power schemes, NGET proposed that there should be symmetric sharing factors of 10% and 30% respectively. Under NGET's proposals, the remaining bundled scheme would have asymmetric linear sharing factors of 20% upside and 10% downside with a fixed cap and floor of £15m.

Quarterly/monthly scheme

2.56. NGET has not proposed separating the scheme into quarterly or monthly targets but has suggested that moving towards summer/winter elements may be appropriate in the longer term.

Ofgem's final proposals

Target

2.57. As set out above, Ofgem considers that NGET's February forecast of £813m, with accompanying automatic downward adjusters represents a reasonable view of anticipated IBC costs for 2009/10.

2.58. We therefore propose that the scheme would use this revised forecast as a central target. However, as we believe there is some uncertainty regarding the costs we are also proposing the inclusion of a deadband of \pm £15m. The proposed target is therefore £798m to £828m.

2.59. We also consider that it is appropriate to include an adjustment mechanism as described above, and therefore propose that the licence condition will give power to the Authority to reduce (but not increase) the target in response to material changes in events which have been agreed between the Authority and NGET prior to the commencement of the incentive period. The level of the adjustment will also be pre-agreed.

2.60. This target includes £258m of constraint costs. However, as stated above, we will be monitoring the development of NGET's review of the commercial and charging arrangements following the urgent review which Ofgem has asked NGET to carry out. If the review results in changes to the commercial and charging rules which govern use of the system, thereby affecting the costs to NGET associated with constraints, we would be looking to ensure that such changes are reflected within the BSIS scheme.

2.61. As set out above, we also propose that the incentive scheme would include the revised new NIA proposed by NGET to better take account of changes in system length and wholesale price. The inclusion of the new NIA changes the central overall incentive target to £615m and hence the deadband would apply between £600m and £630m.

Sharing factors

2.62. We have considered the option of moving towards more variable sharing factors and understand why this option is attractive to both NGET and some respondents by encouraging NGET to invest more time in achieving costs savings within the most likely range. However, we note that the discussion of changing to variable sharing factors has been limited and that given the degree of uncertainty and the inclusion of a wider deadband for 2009/10, we are not convinced of the benefits of including variable sharing factors. We therefore propose to retain the linear sharing factors.

2.63. We have looked at the options put forward by NGET regarding sharing factors which apply to the unbundled scheme. As we are not proposing to unbundle elements of the scheme for 2009/10 our proposals are for the bundled scheme. Given the views expressed by respondents regarding the need to ensure that NGET remain incentivised over a wider range of costs and the particular risks around the 2009/10 forecast we consider it

appropriate to reduce the downside sharing factors to 15%. We consider that the upside sharing factor should be 25% to give NGET a sharp incentive to make efficiency savings.

Cap/floor

2.64. We have considered the options for the cap/floor including whether it is appropriate to index the cap/floor to the overall balancing costs outturn. However, given the current economic climate and the volatility in electricity balancing costs seen this year we also consider it appropriate to limit risk to NGET and customers resulting from the incentive scheme this year. We therefore propose to retain the cap/floor at \pm £15m.

Quarterly/ monthly scheme

2.65. We have considered the option of separating the scheme target into quarterly/monthly blocks and agree with the majority of respondents that the benefits of this option have not been proved and that there is the potential for such separation to skew the incentive. However, as discussed below, we will be asking NGET to develop options for a longer term incentive scheme from April 2010 and as part of that we will expect NGET to look in more detail at whether a move to a summer/winter target separation (for example) would help mitigate risks associated with a longer incentive period.

Parameters

2.66. Our final proposal is shown in Table 2.5.

Table 2.5: Ofgem’s final proposal for the electricity BSIS scheme

	Target (£m)	Deadband (£m)	Upside Sharing Factor (%)	Downside Sharing Factor (%)	Cap/Floor
(New NIA)	615	600 – 630	25	15	+/- £15m
(Old NIA – for comparison)	813	798 - 828	25	15	+/-£15m

Longer term issues

2.67. We consider the move to the New NIA index represents a significant step forward for this year’s scheme. However, there are a number of areas in which we consider further improvements can be made and we will be asking NGET to look at developing proposals with respect to these areas to apply from April 2010. In particular, we consider that there would be significant benefits associated with the implementation of a longer term scheme (although we recognise there are also risks associated with this approach) and will be asking NGET to develop proposals for this.

2.68. In addition, the issues we will be asking NGET to look into in more detail include (but are not limited to):

- New ways of modelling balancing costs;
- Improvements to the new NIA indexation methodology;
- Reactive Power indexation;
- Effect of changes to the parameters of the scheme (including variable sharing factors/ separation of winter/summer incentive period); and
- The effects of increasing levels of renewable generation (particularly wind generation) on balancing costs.

3. Gas external costs incentive scheme from April 2009

Chapter Summary

This chapter outlines the forecasts provided to us by NGG on gas external costs and volumes for 2009/10 and in some cases 2010/11 and 2011/12 and NGG's initial proposals based on those forecasts. It then outlines our views on NGG's forecasts and initial proposals following consideration of the views of respondents to NGG's consultation, and sets out our final proposals for gas external SO incentive schemes to apply from 1 April 2009.

Question box

Question 1: Do you consider that the final proposals for the SO incentive schemes to apply to NGG's external SO costs represent a fair balance of risk and reward?

Question 2: Do you consider that the proposed licence modifications appropriately reflect the final proposals as described in this chapter?

Background

3.1. Unlike electricity, the gas SO incentive scheme is unbundled¹⁸. NGG therefore optimises its performance over each individual component. Unlike electricity SO costs, gas SO costs have been relatively stable over recent years.

3.2. There are some aspects of the current incentive schemes that NGG, industry participants and Ofgem consider have not been working as well as they might. Therefore all parties have worked together over the past year to develop improvements to these areas of the schemes.

3.3. In addition, NGG proposed that some of the individual incentives could be set over a longer term either as enduring incentives (incentives that apply until there is a specific reason to review them) or incentives set for a period of three or five years.

3.4. There are currently five separate areas on which NGG is incentivised independently of each other, which are:

¹⁸ Under the gas SO incentive scheme NGG is incentivised on a number of cost areas independently of each other (each cost area has its own cap/collar and sharing factor). This is different from the arrangements for electricity where there is a single cost target around which NGET is incentivised.

- NTS Shrinkage;
- Operating Margins;
- Residual Balancing;
- Information; and
- Environmental.

3.5. In the following sections, we provide details of the current performance of each incentive scheme, the key issues relating to the development of schemes for April 2009 onwards, NGG's proposals for such schemes, the views of respondents to those proposals and our suggested final proposals.

NTS Shrinkage

3.6. Shrinkage refers to gas (and electricity) that is either used to operate NTS compressors for system operation purposes or gas that is otherwise unbillable or unaccounted for by the measurement and allocation processes. Shrinkage gas needs to be bought by the SO in its capacity as Shrinkage Provider under the UNC¹⁹. The forecast costs to the community for shrinkage in 2009/10 is around £150m.

3.7. Currently, the Shrinkage Incentive encourages NGG to minimise the overall cost of procuring gas and electricity²⁰ to cover the three shrinkage components:

- Compression Energy (Own Use Gas and Electricity) - the energy used to run compressors to transport gas through the NTS.
- Calorific Value Shrinkage (CV Shrinkage) – the energy which cannot be billed as a result of CV Capping under the application of the Gas (Calculation of Thermal Energy) Regulations 1996 (Amended 1997).
- Unaccounted For Gas (UAG) – the energy which cannot be allocated after taking into account all measured inputs and outputs from the system - own use gas, CV Shrinkage and the daily change in NTS linepack. NGG's current view is that UAG is primarily caused by Entry and Exit metering tolerances.

3.8. A £m target is derived from gas and electricity volume forecasts multiplied by gas and electricity reference prices respectively. The volume target is set in advance of the year based on separate forecasts for each of the three elements of shrinkage. The objective of the current Shrinkage Incentive is for NGG to minimise the overall annual cost of shrinkage to the community. NGG can seek to minimise costs by reducing the volumes of shrinkage and/or efficiently procuring gas and electricity. In the following paragraphs

¹⁹ Uniform Network Code.

²⁰ There are currently four electric driven gas compressors on the National Transmission System (NTS).

we discuss the volume forecasts in each of the three areas above and the development of reference prices. Specific incentives on UAG volumes are discussed in the next section.

Volume forecasts

NGG's forecasts

Compression Energy (Own Use Gas)

3.9. NGG's forecasts for Own Use Gas (OUG) are derived from its multi linear regression model which predicts the volume of OUG for a future supply pattern based on historical gas flows from all of the major supply terminals. Supplies from the St. Fergus Terminal are a key driver of OUG and therefore in recent years there has been a link between the incentive OUG volume target and outturn flows through the St. Fergus Entry terminal. However, the outturn volume of OUG has been consistently below the forecast amount in recent years. As OUG is the largest component of shrinkage, NGG has therefore managed to consistently beat the target in recent years, hitting the ceiling payment (£4m) in each of the incentive schemes since 2003/04.

3.10. When developing the scheme for 2008/09 Ofgem was concerned about the accuracy of NGG's model for forecasting OUG and to try to mitigate the effects of any modelling inaccuracy we introduced a scheme based on four quarterly targets.²¹ During Q2 and Q3²² 2008, NGG has performed very close to the target and is currently expecting to receive a cumulative payment of £0.84m (sum of -£0.01m in Q2, £0.8m in Q3 and £0.05m in Q4 2008).

3.11. Following the concerns expressed by Ofgem that the model seemed to be over forecasting these volumes and as part of the development of initial proposals from April 2009, NGG revised its model for forecasting these volumes to put more emphasis on recent performance²³. By way of a sense check NGG reforecast the volumes for 2008/09 and 2007/08 using the new model which showed a significant improvement in forecast accuracy.

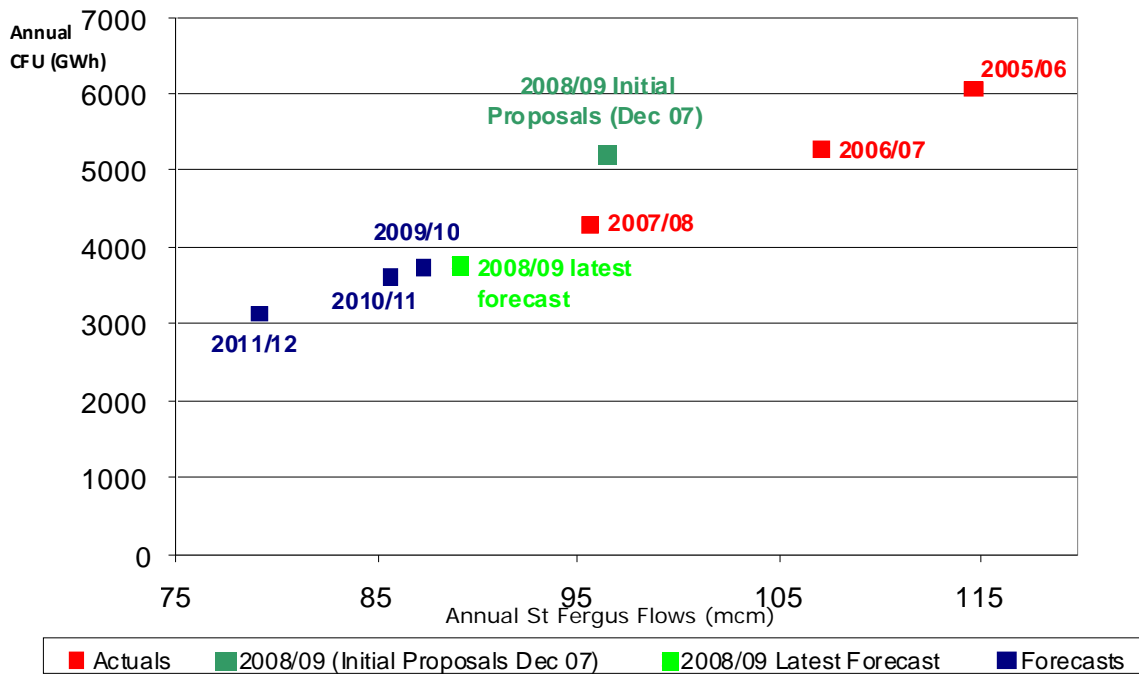
3.12. Figure 3.1 demonstrates the relationship between annual compressor fuel usage and St. Fergus flows. The initial and revised forecasts for 2008/09 (dark and light green points) illustrate the move from the previous model to the revised model which is now based on more recent data.

²¹ By the time the concerns were identified it was too late to revise the model for the 2008/09 scheme in order to improve its level of accuracy.

²² Q2 and Q3 refer to the calendar quarters of the incentive year 2008/09 (April - June '08 and July - September '08).

²³ By increasing the weight given to recent years the model captures recent trends such as increased flows from Easington. It has also considered the effects of flows from the new LNG import terminals at Milford Haven.

Figure 3.1 Relationship between compressor usage and flows through St. Fergus



Calorific Value Shrinkage (CV Shrinkage)

3.13. Determination of the daily CV is set out in the Gas (Calculation of Thermal Energy) Regulations 1996 (Amended 1997). In summary, the methodology detailed in paragraph 4(A) of the Regulations says that the daily CV for a charging zone shall be the lowest of:

- the flow weighted average CV calculated across all of the inputs into the charging zone; or
- the average CV measured at any of the individual input points to the charging zone, plus 1MJ/m³.

3.14. As a result of this legislation not all energy is billed directly to the end customers who use it.

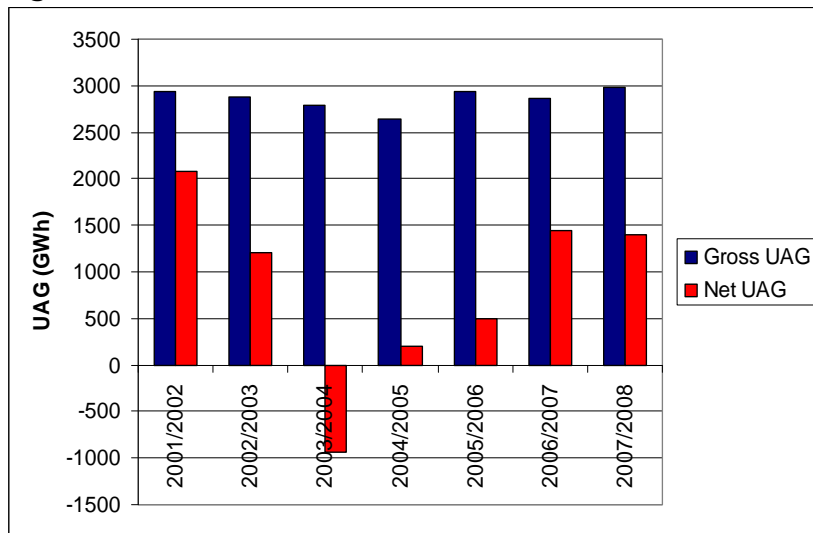
3.15. Last year, specific CV shrinkage risks caused by potential new flows from Milford Haven and Teesside entry points and direct entry of gas onto distribution networks were excluded from the incentive arrangements as Ofgem agreed these risks were outside of NGG’s control. NGG believes these volume risks should continue to be excluded from the incentive arrangements, on the basis of which its forecast of CV shrinkage for 2009/10 and the subsequent two years is 142GWh.

Unaccounted For Gas (UAG)

3.16. In recent years, volumes of UAG have been around a fifth of the size of the compression energy requirement. Volumes for UAG have been incentivised as part of the overall shrinkage volume target.

3.17. Over recent years there has been a rising trend in the net annual UAG volume²⁴. This year it is expected that UAG will cost the industry £70m in commodity charges. Figure 3.2 shows that although net aggregate UAG volumes on an annual basis have been volatile and are currently exhibiting a rising trend, over the same period the gross aggregates of daily UAG volumes have been reasonably constant.

Figure 3.2 Annual UAG volumes



3.18. As a result, NGG has proposed a separate incentive for UAG. This is described in the next section. NGG is proposing that it will still be incentivised on the procurement cost of UAG and therefore that the actual volume required should be passed through in the overall shrinkage scheme.

Target volumes

3.19. NGG believes that irrespective of whether the agreed scheme is annual or quarterly based, the total annual cost target should be broken down into quarters, allowing the

²⁴ NB: unaccounted for gas on the transmission system is expected to be largely due to metering error. It is also possible that errors in NGG’s calculation of linepack could also contribute to UAG, although on a much smaller scale.

appropriate quarterly prices to be applied to the appropriate seasonal volume requirements.

3.20. Table 3.1 shows the annual volumes proposed by NGG for compressor fuel usage, according to the new methodology, for the next three incentive years. NGG has also provided us with this forecast broken down by quarters.

Table 3.1 NGG forecast of compressor fuel usage

Incentive year	Average daily volumetric flow through St. Fergus Terminal (mcm)	Compressor Fuel Forecast (GWh)	OUG Forecast (GWh)	Compression ECE component (elec GWh)
2009/10	87.3	3735	2826	307
2010/11	85.6	3598	2082	509
2011/12	79.1	3139	1498	551

Respondents' views

3.21. In general, respondents agreed with the proposed shrinkage volume forecast. However, two respondents commented that they needed more information to be able to assess the proposal properly. One respondent suggested that the quarterly targets may need some adjustment if they were to be used and another queried whether there were factors other than the incentive scheme driving shrinkage volumes down.

3.22. All respondents agreed that the proposed shrinkage forecasting methodology, a model based on the correlation of compressor fuel use with gas flows from St. Fergus, was appropriate. In addition, one respondent mentioned that the volume target is likely to continue to decrease.

3.23. Respondents also agreed with the idea of a separate UAG scheme, these views are discussed further below.

Ofgem's views

3.24. We consider that the new model that NGG has developed to forecast compressor fuel usage is a significant improvement. We have undertaken considerable analysis concerning the model which shows that it is reasonably accurate in forecasting compressor fuel usage when linked to flows through St. Fergus. We therefore consider that it is appropriate to use this model to forecast OUG for the next three years.

3.25. We also accept that the volume risks regarding CV shrinkage associated with potential new flows from Milford Haven and Teesside and direct entry of gas onto distribution networks should be excluded from the incentive scheme. We therefore agree with NGG's forecast of CV shrinkage of 142GWh, which is slightly lower than its forecast for the current year.

3.26. However, we expect NGG to look at ways of taking forward, with industry, a review of CV shrinkage, which could, for example, include reviewing the daily CV methodology. If a review resulted in a change to the volume of CV shrinkage to be included in the incentive scheme we would need to revisit the setting of the volume within the scheme.

3.27. We agree with NGG that it is appropriate to set a separate incentive concerning UAG volumes and therefore it is appropriate to pass through these volumes within the Shrinkage Incentive, such that NGG remains incentivised on the purchasing of these volumes.

3.28. Finally, we also agree with NGG that it is appropriate to break down the volume into quarters, such that the incentive is based on seasonal volumes and prices.

Reference price

3.29. A gas cost reference price (GCRP) and electricity cost reference price (ECRP) are used as the benchmarks against which NGG's procurement strategy can be judged. As part of last year's consultation process, a mix of year ahead and more prompt (monthly) wholesale market prices was agreed as the GCRP to apply until 2012 (the end of this Transmission Price Control period) to avoid uncertainty. The GCRP for each quarter is calculated by applying a 75% weighting to the average price of a quarter contract over each day in the year t-1 and a 25% weighting to the average price of a monthly contract over each day in the preceding month. An interim ECRP was also established for 2008/09 for one year. The ECRP was only set for one year to allow consideration of potential alternatives during this year's review process.

GCRP uplift

3.30. The GCRP methodology is used to provide a cost reference for a reasonable procurement strategy for shrinkage assuming the shrinkage profile is flat. However, on any day NGG will need to undertake residual buy or sell trades to fine tune the procurement position to meet the daily shrinkage allocation. The volume for these daily buys and sells are referred to as the swing volumes. The costs associated with these actions are currently captured through an uplift to the GCRP (the GCRP uplift).

3.31. The current GCRP uplift of 0.055p/kWh was set in 2001 based on the costs of meeting the daily volatility requirement from the Rough storage facility and has not been reviewed since.

NGG's proposals

3.32. NGG has proposed changes to the GCRP uplift this year. NGG has proposed two approaches to benchmarking the costs associated with the procurement of these swing volumes, either through reference to a storage service, as now²⁵, or prompt market prices.

Respondents' views

3.33. All respondents agreed it was timely to reassess the methodology behind the GCRP uplift, one respondent suggested it should be looked at in concert with UAG and residual balancing. There were mixed responses to how the GCRP uplift should be set. Two respondents favoured a scheme based on ex-ante storage costs, one respondent favoured an ex-ante approach but did not specify a particular method and one respondent supported the use of an ex-post market price.

Ofgem's views

3.34. We agree that it is appropriate to review the value of the GCRP uplift, given the period of time since it was last reviewed. However, we consider that setting the GCRP uplift on an ex-ante basis based on storage is correct, and therefore propose to keep the same methodology, whilst updating the value as proposed by NGG.

ECRP and ECRP uplift

3.35. NGG has to procure electricity for the electric driven compressors on a retail basis which attracts delivery charges (Distribution Use of System and Transmission Network Use of System) and other retail costs over and above wholesale prices. As part of last year's process the retail commodity uplift over wholesale price was established at 16% + delivery charges. These equivalent retail and delivery costs are not incurred for gas volumes which are purchased on the wholesale market through the shrinkage provider account.

3.36. In its August 2008 consultation NGG suggested that an alternative approach would be for NGG to set up as an Electricity Supplier to purchase the electricity for the electric drives at wholesale prices. The consultation asked whether the industry would have any concerns with this approach and if so how the costs of setting up a supply business should be treated. Based on the consultation responses NGG is not proposing to take this approach forward at present.

²⁵ At the time of its Initial Proposals an indicative figure of 0.219p/kWh was calculated, based on the prevailing forward prices for Rough at that time. This figure has been updated to reflect latest prices, with a revised value of 0.237p/kWh.

3.37. In order to derive an appropriate retail benchmark for NGG’s procurement there was support for the continuation of the existing arrangements with an ECRP based on wholesale prices with a retail uplift and separate treatment of delivery charges.

NGG’s proposal

3.38. Last year an interim ECRP was set on a quarterly basis for one year. For each quarter the ECRP is based on the average March 2008 forward prices for that quarter.

3.39. With uncertainty over the exact commissioning dates and until the operation of the new drives beds in, NGG is unlikely to procure electricity at year ahead as it does with gas. To reflect the likely strategy of purchasing of electricity closer to its period of use, and the reasonably flat profile of expected use, NGG has proposed an ECRP constructed from a wholesale published price index (e.g. Heren) as the average wholesale baseload price for a quarter contract over each day in the month immediately preceding the delivery quarter, as summarised in Table 3.2.

Table 3.2 Proposed ECRP

Quarter	Apr-Jun	Jul-Sep	Oct-Dec	Jan-Mar
ECRP set using the average quarterly forward prices	Mar	Jun	Sep	Dec

3.40. This wholesale price would then be uplifted by 16% to reflect retail commodity costs and to derive the ECRP for each quarter. NGG has subsequently proposed that this be increased to 18% to reflect increases in BSUoS charges and renewable obligation costs. The relevant TNUoS and DUoS tariffs would also be added to the overall cost incentive.

Respondents’ views

3.41. In general, respondents agreed that the ECRP should be enduring. However, one respondent requested further analysis to verify that the 16% retail uplift was appropriate.

Ofgem’s views

3.42. Ofgem agrees that given the uncertainty regarding the required volumes for electric compressors it is appropriate that the ECRP reference price is set on a quarterly basis using the average forward price during the month prior to the start of the quarter. We have undertaken analysis which shows that it is correct to increase the ECRP uplift to 18%. We propose that the delivery charges are based on the actual tariffs applicable for each year.

Shrinkage Incentive Scheme

NGG’s proposal

3.43. NGG proposed two separate options for 2009/10 which are shown in Table 3.3.

Table 3.3 NGG’s proposals

	Upside share	Downside share	Quarter Cap (£m)	Quarter Floor (£m)	Annual Cap (£m)	Annual Floor (£m)
Current	25%	20%	0.8 (S) 1.2 (W)	-0.6 (S) -0.9 (W)	4	-3
Option 1 Annual Scheme	25%	20%	-	-	5	-4
Option 2 Quarterly Scheme with overall Annual Cap/Floor	25%	20%	1.5 (S) 2 (W)	-1.5 (S) -2 (W)	5	-4

Note: S denotes the summer quarters (Q2 2009 & Q3 2009)
W denotes the winter quarters (Q4 2009 & Q1 2010)

3.44. These proposals are variations on the current scheme with changes to caps/floors and scheme duration. NGG also believes that this scheme could be set as a multi year incentive.

Respondents’ views

3.45. Three respondents preferred annual shrinkage schemes while two favoured quarterly schemes. All respondents preferred annual schemes to multi-year schemes. Most respondents agreed that UAG volumes should be passed through however, some comments were qualified with concerns about the UAG scheme itself.

Ofgem’s final proposal

3.46. Given that we now have confidence in the modelling approach used to forecast OUG and we are proposing to pass through the UAG volumes for three years (see discussion below on the proposal for a separate UAG scheme), we consider that it is appropriate to set the Shrinkage Incentive for the next three years, i.e. up to the end of the current price control. Whilst we considered the views of respondents on this point, we believe that a multi-year scheme will provide NGG with the opportunity to consider ways to improve its operation of its compressors and the way in which it purchases gas and electricity over a longer period, which should result in greater improvement.

3.47. Given the above, we do not consider that it is appropriate to break the scheme down into quarterly caps and floors, but we do consider that it would be appropriate to increase

the annual cap and floor. Our final proposal is therefore Option 1 (as included in Table 3.3) of NGG's schemes for three years.

UAG Incentive Scheme

3.48. As previously stated, UAG is the gas that remains unaccounted for after all inputs and outputs from the system have been measured. NGG's current view is that this is primarily the result of inaccuracies in metering resulting from inherent metering tolerances, and can result in both under and over measurements²⁶. Net positive unaccounted for gas volumes have been gradually increasing in recent years, increasing shrinkage payments that are socialised to all Shippers²⁷.

3.49. In response to industry concerns, NGG has accepted that it is best placed to take action to try to reduce UAG and has proposed, from 2009 onwards, that UAG volumes be incentivised in a different way through a new incentive which uses annual gross (or absolute) levels of UAG as the performance measure.

3.50. NTS UAG is in reality an accounting tool which directs net volumes that cannot be allocated to other accounts (e.g. meters) to the shrinkage provider account. Whilst the existing Shrinkage Incentive recognises and focuses attention on the net costs associated with the costs socialised through shrinkage it does not recognise the misallocations. Table 3.4 summarises how there will be individual parties who gain and lose as a result of the misallocation of volumes under every individual meter error.

Table 3.4 Summary of effects of UAG on parties

	Impact on Shippers at the affected meter	Socialised impact on all Shippers
+ UAG Gas metered in exceeds gas metered out. Gas has been 'lost' from the network.	Gain Through either not paying for gas that they have actually taken or being paid for putting more gas into the system than they actually have.	Loss Increase in commodity charge
- UAG Gas metered out exceeds gas metered in. Gas has been 'created' in the network.	Loss Through either paying for gas that they have not actually taken, or being paid for putting less gas into the system than they actually have.	Gain Decrease in commodity charge

²⁶ Note that this is not losses or theft of gas.

²⁷ This year it is expected that Unaccounted for Gas will cost the industry £20m in commodity charges (although the value of absolute error of UAG is nearer £40m).

NGG's proposed scheme

3.51. NGG proposed that the incentive be set over five years and be aimed at tackling gross UAG levels. NGG considers that this reflects the true cost of UAG as well as the nature of the work that NGG would need to undertake to identify the causes of the increase.

3.52. **Target** – NGG's proposal for a volume target is the average of the historic data from 2001/02 onwards. To ensure the most up to date target is set, NGG has stated that in the final scheme the target should be set to include the outturn gross UAG level from 2008/09, (i.e. the target would be the average of 2001/02 to 2008/09). Based on the completed years 2001/02 to 2007/08, the target would be 2862GWh²⁸.

3.53. **Duration** - The activities that NGG may undertake as a result of this incentive might include witnessing additional meter validations, which given the size of the meter population could take a number of years²⁹ before any potential benefits are observed. Given the potential costs and timescales for delivery of any benefits NGG has proposed that the scheme should be an annual scheme but set for five years.

3.54. **Risk/Reward Profile** - NGG has suggested it will be incurring additional costs in attempting to reduce UAG which would be done so without a guarantee of delivering a benefit against the incentive target. NGG therefore believes that the incentive should be upside only recognising that incurring costs is an implicit downside to the scheme.

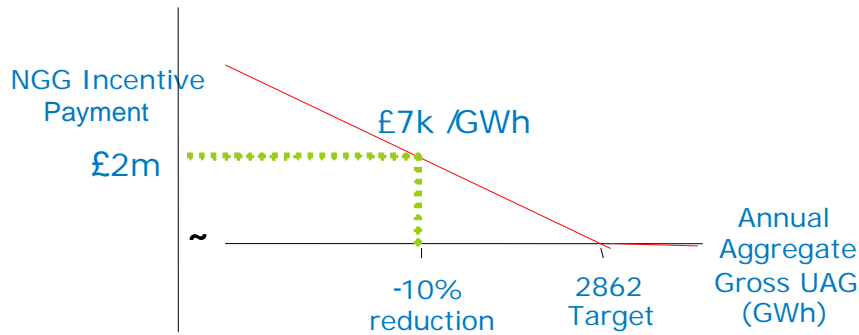
3.55. **Incentive Value** - NGG has proposed that the financial incentive parameters be set by valuing UAG misallocation at a market price, and then sharing the benefits of any reductions of UAG between Shippers and NGG. NGG has proposed that any benefits delivered be shared equally with Shippers. NGG has therefore applied a 50% sharing factor which gives an incentive value of £7k/GWh of reduction to the gross annual level of UAG.

3.56. A schematic presentation of the scheme proposed is shown in Figure 3.3.

²⁸ As a result of a significantly higher gross UAG level in 2008/09, NGG has proposed to Ofgem that this figure should not be included in the calculation of the target.

²⁹ Including time to recruit and plan for visits and to actually carry out visits to the identified sites, which may take more than one visit to deliver benefits.

Figure 3.3 NGG proposal for UAG scheme



Respondents’ views

3.57. Most respondents agreed with the idea of a separate UAG scheme. However, one suggested that a fundamental review should be carried out before embarking on solutions. One respondent suggested a three year scheme was most appropriate while another suggested an initial one year scheme, as NGG’s ability to influence UAG levels was unclear. Two respondents stated they thought the appropriate measure was net UAG volumes as opposed to gross.

3.58. In terms of scheme parameters, several respondents suggested that a rolling average should be the basis for the target, while one suggested the target should be set on the lowest net volume seen in the past five years. One respondent suggested a downside sharing factor and a collar were appropriate while another respondent suggested that the parameters should reflect the business costs NGG incurs against what is an uncertain outcome. One respondent suggested that the incentive should be based on the difference in the value of UAG gas bought and sold by NGG with reference to the system average price on the relevant day. One respondent suggested that there needs to be a review of NGG’s obligations regarding meter validation, while another suggested that this was BERR’s remit as opposed to NGG’s.

Ofgem’s final proposal

3.59. We have held a number of discussions with NGG regarding this incentive since the publication of its initial proposals to make sure that any UAG scheme would be in the interests of customers. We raised concerns with elements of NGG’s proposals such as whether the lack of downside, combined with no cap could result in significant financial flows to it and an unjustified amount of management time being spent on this incentive in relation to the rest of the incentive bundle. We were also concerned that five years was a long period for an incentive particularly given that the current price control expires in 2012.

3.60. As a result of these concerns and following discussions with NGG we have developed an alternative option for a scheme for UAG which we consider represents a better balance of risk and reward for NGG and customers. The option retains the target as in NGG’s proposal and does not have a downside, based on the assumption that NGG will incur

costs in attempting to reduce UAG. This option is our final proposal and is summarised in Table 3.5.

Table 3.5 Final proposal for UAG scheme

	Duration	Target	Payment cap	Sharing factor	Incentive value to NGG
NGG proposal	5 years	2862 GWh	Uncapped	50:50	£7k/GWh
Ofgem final proposal	3 years	2862 GWh	Year 1: £2m Year 2: £3m Year 3: £5m	33:67	£4.67k/GWh

Operating Margins

3.61. Operating Margins (OM) gas is gas that is available to NGG as SO to use to manage certain system events. Operating Margins (OM) services are purchased by NGG on an annual basis in line with both the requirements of the UNC and obligations placed on NGG through its Safety Case. Requirements for OM gas are determined through network simulation analysis. The requirement is for the physical delivery of additional gas to maintain safe pressures within the NTS during a System Event, until other measures take effect. Potential System Events are split into three categories:

- Group 1 (Major events) e.g. loss of supply infrastructure, loss of largest sub-terminal;
- Group 2 (Multiple events) e.g. compressor failures, pipe breaks; and
- Group 3 (Orderly rundown) maintain pressures in the event of a National Gas Supply Emergency (NGSE).

3.62. Because of the nature of the service (i.e. the gas needs to be available, but is rarely used) the majority of NGG’s costs relate to the cost of holding the gas in store. NGG is currently incentivised on both the holding costs and the utilisation costs as summarised in Table 3.6. NGG is expected to gain £2.26m under this scheme for the incentive year 2008/09.

Table 3.6 Current OM incentive scheme

Scheme	Target (pending C3 prices)	Holding Cost Cap	Holding Cost Floor	Upside Sharing Factor	Downside Sharing Factor	Utilisation Cost Floor
Current	£23.57m	None	none	100%	100%	£-0.5m

OM Contestability

3.63. To date, OM services have been provided by storage facilities as a result of their strategic location on the extremities of the network, implicit availability and the high deliverability rates which are necessary for OM purposes. Under Special Condition C25 of its Gas Transporter Licence NGG has an obligation to use reasonable endeavours to promote competition in the provision of OM by 1 April 2009.

3.64. NGG recently undertook a tender process for the provision of OM services. As a result of uncertainties surrounding the outcome of the tender round, at the time of its final report NGG proposed an incentive on the utilisation aspect of this service only and a pass through of the holding costs for 2009/10.

3.65. To set a target for holding costs requires a forecast of the volume requirements, knowledge of the sites that can meet these requirements and a forecast of the costs associated with service from these facilities. With the introduction of the contestable tender in 2009 NGG considered that there is uncertainty in all of these areas.

- **Volume requirement** – In order to prove the capability of any new providers there may be a requirement to over procure against the requirements until the capability of new providers is demonstrated to the satisfaction of the industry and the HSE.
- **Service Providers** – Until the tender had been held it was not possible to determine which new sites, or even which types of new sites may offer an OM service.
- **Provider costs** – Until the tender had been held it was not possible to accurately forecast the likely service costs for 2009 onwards as there was uncertainty over whether the current price restrictions that the NG LNG facilities are subject to would be lifted by Ofgem, and the timing of this.

NGG’s proposed scheme

3.66. For these reasons NGG proposed that for 2009/10 the holding costs associated with OM should operate on a cost pass through basis, but that NGG should remain incentivised on the utilisation element, as summarised in Table 3.7.

Table 3.7 NGG’s proposal for OM

Scheme	Utilisation Target	Upside Sharing Factor	Downside Sharing Factor	Utilisation Cost Floor
Proposed	£0.27m	100%	100%	£-0.5m

Respondents’ views

3.67. Most respondents agreed that OM holding costs should be passed through given the uncertainty caused by the move to contestability. One respondent suggested that the current scheme should be continued but with separation of contested and uncontested holdings as soon as practical, another respondent suggested there should be a ceiling on costs. One respondent voiced a general concern that OM contestability was likely to increase costs, while NGG should be incentivised to reduce costs. No respondents provided an alternative approach to incentivising holding costs.

3.68. All respondents agreed that the current utilisation component of the OM scheme should be continued but will need to be reviewed as new providers under contestability may increase costs or incur costs in different ways.

Ofgem's Final Proposal

3.69. On 20 February 2009, we published our decision letter³⁰ in respect of the outcome of NGG's tender for the provision of OM services. In that letter we explained that we considered that significant progress had been made towards contestability and that effective competition is likely to be possible in the future. We also confirmed that we considered it appropriate, as part of the development of contestability, for NGG to recover the additional costs it may incur as a result of facilitating a change to the Safety Case under the SO external cost incentive revenue.

3.70. Given the ongoing development of contestability, we consider that there remains uncertainty regarding the holding costs that NGG will incur in 2009/10 and therefore these costs should be passed through but that NGG should remain incentivised on the utilisation costs. Our final proposal is therefore as per NGG's proposal. We will continue to monitor the costs incurred by NGG in the provision of OM and also the development of OM contestability.

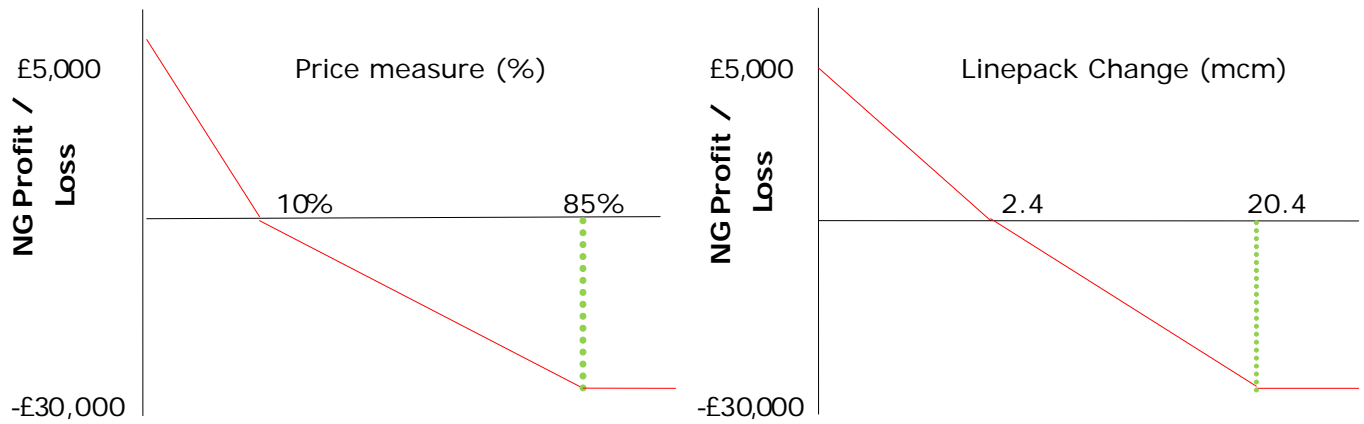
Residual Balancing

3.71. The incentive scheme for residual balancing is formed of two interacting measures. The Price Performance Measure (PPM) incentivises NGG to minimise the impact of trades that it takes to balance supply and demand on the market. The Linepack Measure (LM) incentivises NGG to ensure that the gas in the system (the Linepack) at the end of each trading day matches that at the start. This helps ensure that the costs of resolving imbalances are accurately targeted on those who caused them, by encouraging NGG to resolve any imbalances on the same day.

3.72. The parameters of the current incentive scheme for residual balancing are illustrated in Figure 3.4.

³⁰ "Operating Margins (OM) Contestability", Ofgem, 20 February 2009.

Figure 3.4 Current parameters of residual balancing scheme



3.73. Historically, NGG has gained under this scheme and our current forecast is a payment to NGG of £1.4m at the end of this incentive year, with an average monthly payment (Apr-Nov) of £118k under the Price Performance Measure (PPM), that has been beaten 94.3% of the time so far, and an average monthly payment (Apr-Nov) of £13.7k under the Linepack incentive, that has been successfully achieved 64.3% of the time.

NGG’s proposed scheme

3.74. The industry consultation carried out in 2008/09³¹ confirmed that minimal market intervention by the residual balancer should continue to be a key objective for a Residual Balancing Incentive and that the current structure of the PPM was working correctly. Views with respect to the LM were mixed. Most (but not all) participants considered that there was value in keeping some kind of linepack incentive in order to prevent large imbalances being transferred between days. However, there was general support for widening of the current linepack tolerance target of 2.4mcm.

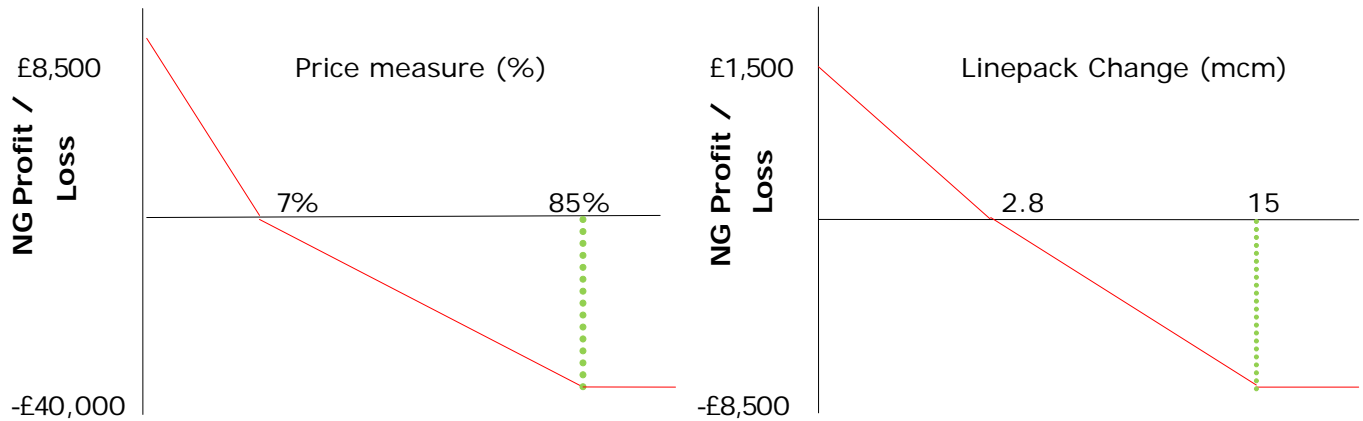
3.75. In response to these views, NGG put forward two distinct options alongside the current scheme, for the Residual Balancing incentive to apply from April 2009 (set out below).

3.76. Option one: this option changes the balance between the PPM and LM, with a stronger incentive on PPM and a weaker incentive on LM than at present. NGG suggests that this scheme should lead to NGG taking fewer balancing actions than at present as the considerations over the linepack incentive would be less prominent in the operational strategy developed for each day. Option one, illustrated in Figure 3.5, also includes a

³¹ NGG’s mini consultation on shrinkage and Residual Balancing Issues, Issued 22 August 2008, available on: <http://www.nationalgrid.com/uk/Gas/soincentives/docs/>

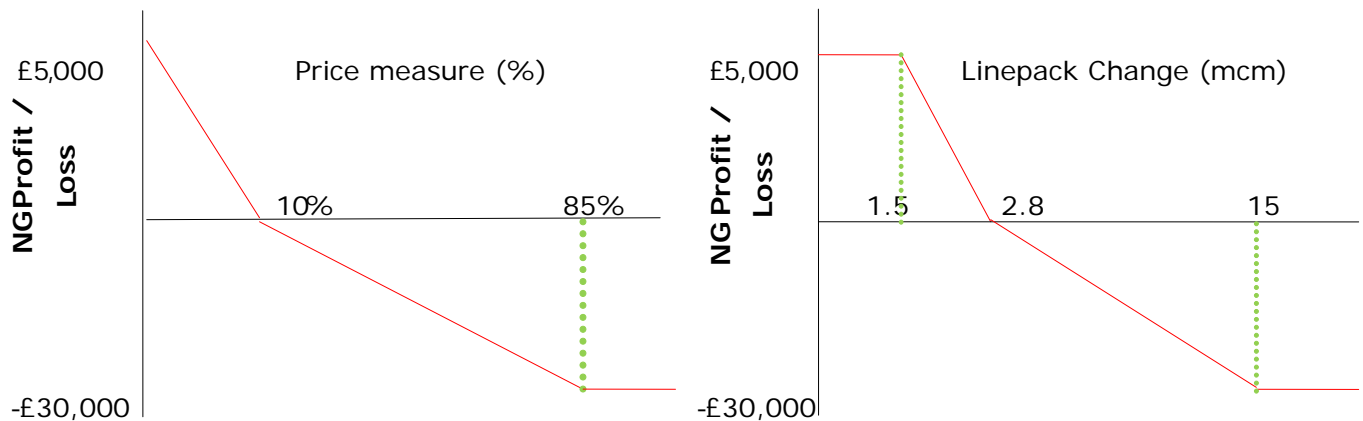
wider tolerance level for linepack variations of 2.8 mcm rather than 2.4 mcm. The PPM target is also tightened from 10% to 7% to increase the incentive on NGG.

Figure 3.5 Parameters of residual balancing scheme: NGG Option one



3.77. Option two: this option is similar to the current incentive with some changes to the LM scheme. Under the option, illustrated in Figure 3.6, once the closing linepack is close (within 1.5 mcm) to opening linepack the incentive payment would be flat to remove incentives on the SO to 'fine tune' the system. The downside sharing factor is also made steeper to ensure that large imbalances are not carried forward to the next gas day to promote cost target. As with option one the LM target would be increased to 2.8 mcm.

Figure 3.6 Parameters of residual balancing scheme: NGG Option two



Respondents' views

3.78. In respect of the alternative residual balancing proposals, two respondents favoured option 1 and three preferred option 2. One respondent suggested a roll-over of the

current scheme combined with the PPM component of option 1. In addition one respondent commented that the scheme should not have any value until the linepack change reaches 10mcm and from that point onwards it should act to negate any value from the PPM for that gas day. Most respondents suggested that the schemes be reviewed and set annually.

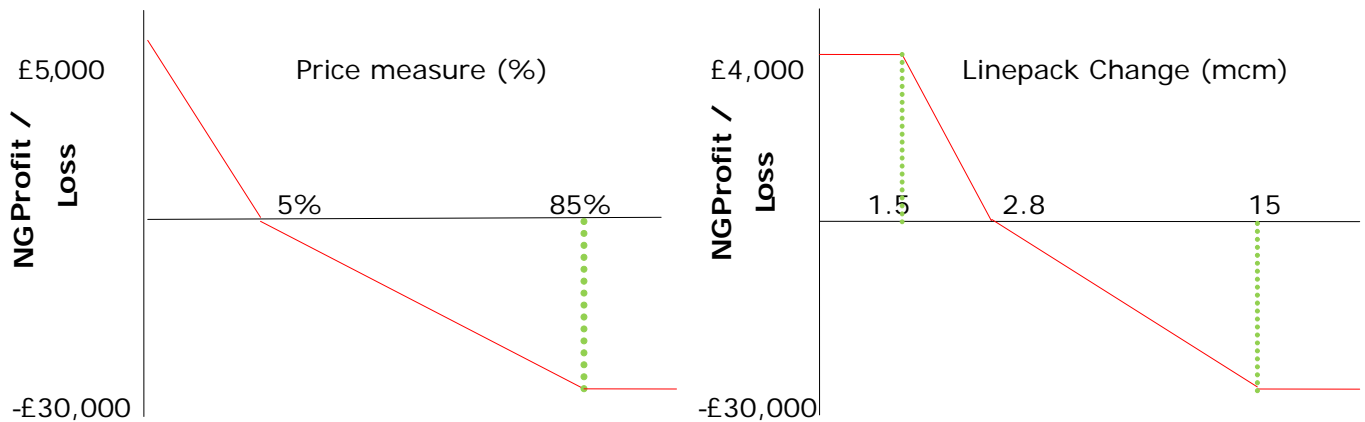
Ofgem’s final proposals

3.79. As outlined above, industry representatives were unanimous in the view that they wanted the incentive on NGG not to enter the market to be strengthened in relation to the linepack measure (although most did not consider it appropriate to remove the linepack measure entirely). Our final proposal is therefore to change the residual balancing incentive to:

- Sharpen the incentive on NGG not to enter the market and if it does to trade close to the system average price;
- Introduce a deadband in the linepack measure to remove the incentive on NGG to resolve small variances in linepack; and
- Lower the maximum payment for the linepack incentive relative to the price measure to place greater emphasis on the price measure.

3.80. The parameters of our Final Proposal, which we consider should be implemented for one year, are shown in Figure 3.7.

Figure 3.7 Parameters of residual balancing scheme: Ofgem proposal



Information

3.81. Information provision has two components: demand forecasting accuracy and data publication.

3.82. The incentive scheme is based on a daily measure of NGG’s performance against a target (the deviation of the day-ahead demand forecast from the outturn figure for that

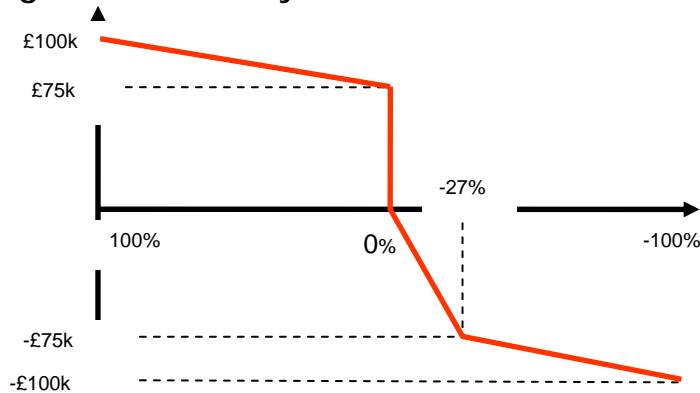
day and the availability and timeliness of the publication of certain data such as demand and flows on to the network).

3.83. **Demand Forecasting incentive** - The current scheme parameters derive a target of an absolute demand forecast error of 3.5%, with upside and downside gradients that give a profit or loss of £1.6m for a 5% increase or decrease (respectively) in performance around this target. There is a shallower upside gradient for performance increases above this up to a maximum payment of £9.2m for a zero demand forecast error.

3.84. Under the demand forecast incentive NGG is projected to earn between £2.3m and £3m this year, due to the successful achievement of an average forecast error of 2.69%, well below the current 3.5% target, based on November forecast.

3.85. **Information Publication incentive** - The scheme implemented for 2008/09 had the objective of maintaining the prevailing level of performance, which had significantly improved in recent years. Under the scheme NGG earns £75,000 if it meets the performance benchmarks for timeliness and availability, with a possibility to earn a further £25,000 for additional over-performance up to a 100% improvement. The scheme has a £100,000 penalty should performance fall below the benchmark. The scheme is summarised in Figure 3.8. In addition NGG has an “improved performance” scheme that allows NGG to earn 6% return on the investment it plans to make to deliver performance enhancement so long as these investments bring the anticipated results.

Figure 3.8 Summary of Information Publication incentive



Demand Forecasting Target

NGG’s proposal

3.86. NGG has proposed a simple roll-over of the scheme parameters with a tightening of the daily target of forecast error from 3.5% to 3.2%. This target would be above the average daily error seen this year (likely to outturn at around 2.8%). NGG has indicated that this is appropriate because of two market developments which NGG believes pose a significant new risk to the accuracy of its demand forecasting in 2009/10:

- Aldbrough is a new mid range storage (MRS) site, which in 2009/10 is expected to have six out of its nine caverns commissioned. Given the existing maximum injection of the existing MRS portfolio (23 mcm/d) the Aldbrough site represents an increase of 56% on the total maximum potential MRS demand. This, according to NGG, significantly increases the demand forecasting uncertainty associated with this type of site whose operational behaviour is less easy to forecast compared to traditional weather related demands. Predicting the behaviour of this site may also be more difficult compared to other sites given the dual ownership of the site as this could potentially create different drivers in relation to the use of the facility.
- Flows from the Milford Haven LNG importation terminals are expected in 2009/10. However, given the unique shipping related drivers associated with LNG NGG considers it is difficult to predict the days on which LNG will flow and what the impacts of these flows would be on UK prices and demands on the Interconnector³². One example being that LNG could transit through the NTS into continental Europe through interconnector exports.

Respondents' views

3.87. Three respondents to the quality of information - demand forecasting incentive proposal agreed that the target should be set at 3.2%. Two respondents suggested that 3.0% was more appropriate with one of these respondents suggesting that there be a downside gradient to reduce the impact on NGG in the case of high activity at Aldbrough and Milford Haven.

Ofgem's Final Proposal

3.88. We recognise that there is the possibility of some additional risk to NGG's forecasting accuracy resulting from the commissioning of Aldbrough (although it remains unclear what volume will be commissioned during 2009/10) and the Milford Haven LNG import terminals. However, our analysis suggests that the risk is not as significant as NGG has suggested. In addition, we also consider that it is appropriate, particularly in this area where the benefits of accurate forecasting are as significant to the market as a whole, that NGG should be incentivised to continually improve its forecasting methodology.

3.89. Our final proposal is therefore that NGG's demand forecasting target is set at 3%.

³² We understand that NGG is referring to IUK in this context.

Demand Forecasting Scheme Parameters

NGG's proposal

3.90. NGG's proposal is that the parameters of the demand forecasting scheme are kept the same as the current scheme and set for one year.

Respondents' views

3.91. With regards to the period of the incentive, three respondents thought it should continue to be reviewed annually. One agreed that an enduring incentive could be set if the target reduced annually and was linked to the residual balancing incentive.

Ofgem's Final Proposal

3.92. Given the benefit to the market of the tightening of the target, our final proposal is as per NGG's proposal for one year, with the tightening of the target.

Information Publication incentive

NGG's proposal

3.93. NGG has proposed to rollover the incentive unchanged, as shown in Table 3.8. This would mean that NGG earns £75,000 if it meets the performance benchmarks for timeliness and availability, with a possibility to earn a further £25,000 for additional over-performance up to a 100% improvement. The scheme has a £100,000 penalty should performance fall below the benchmark.

3.94. In addition, a mechanism was established for one year to allow NGG to recover the costs (with a six percent uplift), subject to Authority consent, of approved website performance improvement investments, in the event they delivered the expected benefits.

Table 3.8 NGG's proposal for Information Publication Scheme Parameters

Scheme	Target	Cap (£)	Floor (£)
Proposed	Performance benchmark: Website availability 99.3% Website timeliness within 10 mins on 90.50% of occasions	100k	£100k

Respondents' views

3.95. Four respondents thought that this incentive should be removed altogether. Two respondents thought the incentive should continue and of these two, one thought the incentive should be set for the remainder of the price control.

3.96. If the overall incentive is to be retained, there were mixed responses to whether funding for the website upgrade should be continued. Two respondents thought the incentive should be removed, one thought it should be enduring and one suggested that further funding should be set as part of the price control. One respondent queried the continuation of the incentive commenting that Phase 2 of the Market Information Provision Initiative (MIPI) had already been sanctioned.

Ofgem's Final Proposal

3.97. We note that the majority of respondents to NGG's consultation considered that these information incentives should be removed. However, it should be noted that no responses were received from small suppliers or large customers and we recognise the importance that these parties place on this information. We therefore consider it is appropriate to retain these incentives at the same level as for the current year for a further year and plan to discuss this issue with small suppliers and large customers. Last year NGG was also incentivised, through a one year website performance improvement scheme, to retain the costs of any investments to further improve website performance. It is proposed to retain this mechanism also for the incentive year 2009/10.

Environmental

3.98. This scheme incentivises NGG to reduce natural gas emissions associated with gas compressor venting. A direction to implement an environmental incentive relating to methane emissions was issued on 9 September 2008. A summary of the scheme is provided below:

- One year scheme from 1 April 2008 to 31 March 2009;
- The scheme applies to the amount of natural gas vented from gas driven compressor units;
- The target amount of venting (based on the average of the last seven years data) was 2086 tonnes of natural gas;
- As a result of concerns over windfall profits or losses a deadband of $\pm 5\%$ was set around the volume target (1982 - 2191 tonnes);
- A reference price for any volume vented above or below the deadband of £437/tonne of natural gas³³;
- The scheme has no sharing factors, caps or floors; and
- In the context of this scheme, venting means the release of gas from a gas turbine driven compressor as a result of starting a compressor, purging a compressor, depressurising a compressor and the leakage of gas through a seal around the shaft of a compressor.

³³ This price derived from Defra's 2008 shadow price of carbon £26/tCO₂e converted to the methane equivalent by multiplying by a factor of 21 (the global warming potential (GWP) of methane) and multiplied by 0.8 (natural gas is 80% methane by weight).

3.99. It should be noted that the current scheme does not include any volumes vented from electric compressors, as these are not currently measured. As part of the development of a scheme from April 2009 we asked NGG for information in respect of the development of measuring facilities.

NGG’s Proposal

3.100. As this incentive has only been in place for one year NGG proposed that it should be retained on a similar basis for next year with changes to the target to reflect this year’s outturn volume. In addition NGG proposed two alternative options for the reference price used in the incentive: that it should be uplifted to represent the environmental cost of all of the components of natural gas, or it should remain as it is to just reflect methane. NGG’s proposal is summarised in Table 3.9.

Table 3.9 NGG’s proposal for Environmental incentive scheme

Scheme	Target	Dead-band	Reference price (£/tonne)	Cap/Up-side Sharing Factor	Floor/Downside Sharing Factor
Current	2086 t	±5% (1982 – 2191)	437	None	None
Proposed A	Average of 2001-2008 data	±5%	570	None	None
Proposed B	Average of 2001-2008 data	±5%	464	None	None

3.101. Scheme A ensures that at the margin the environmental costs associated with an additional tonne of gas vented from a compressor unit are fully factored into NGG’s decision making process (i.e. not just the environmental cost of methane).

3.102. Scheme B is effectively a roll forward of the existing incentive. The only change would be the resetting of the volume target for 2009/10. This option only reflects the environmental cost of methane, i.e. it does not fully reflect the environmental costs associated with an additional tonne of natural gas vented but may be viewed as an acceptable alternative given that the incentive has not yet run for a full year.

3.103. Subsequent to its initial proposals NGG has provided us with the actual volume of methane vented during 2008. This figure of 1534 tonnes was significantly lower than the totals in previous years, which were used to set the target for 2008/09. In addition, NGG has provided Ofgem with information regarding how it can measure methane vented from electric compressors.

Respondents’ views

3.104. Four respondents favoured scheme A (reference price factors in all natural gas components), however one respondent was concerned that this price seemed high relative

to the market price. One respondent favoured neither scheme and suggested that the EU ETS allowance price be used.

3.105. Three respondents agreed that the average volume from the past eight years should be used as the target, although one respondent suggested that this should be reviewed subject to the additional information received via the information request (relating to the measuring of emissions from electric compressors) and another suggested it should be adjusted in line with the electric driven compressor changeout programme. One respondent suggested that the target should be based on the lowest annual volume from the past eight years, while another suggested that the second lowest annual volume should be used.

Ofgem's final proposal

3.106. Given the significant reduction in volumes seen during 2008, we consider that it is appropriate to put greater weighting on this year when setting the target, as we believe that this decrease is the result at least in part to efficiency savings driven by the incentive. However, we recognise that it is only one data point and that there could have been other conditions partly driving the reduction. We therefore propose to set a target from a weighted average of the last three years of volume vented using 3:2:1 (3 being the most recent). We also propose to retain the deadband of $\pm 5\%$. Following consideration of information provided by NGG relating to the measurement of volumes vented from electric drive compressors we also consider it appropriate to include emissions from electric compressors within this target.

3.107. Our final proposal is therefore for a one year scheme with a volume with a deadband range of 1688-1865 tonnes of natural gas vented. We also consider that it is more appropriate to use a reference price that factors in all natural gas components. Our final proposal is therefore for a reference price of £574/tonne which factors in all natural gas components.

3.108. In addition, when setting the current incentive we also asked NGG to consider further the possibility of including an incentive on fugitive emissions. We still consider it appropriate for NGG to come forward with initial proposals for such a scheme during 2009.

Maintenance incentive

3.109. Several respondents to NGG's consultation considered that it would be appropriate for NGG to be incentivised in some way on its maintenance regime. Our understanding is that this relates to the rearrangement of maintenance days.

3.110. We therefore consider that it is appropriate for NGG to consider this further.

Summary table

3.111. Table 3.10 presents an overview of the proposed schemes and a summary of NGG potential gain/loss.

Table 3.10 Summary of Ofgem's Final Proposals

Incentive	Max profit ³⁴	Max loss	Explicitly defined cap/floor	Comments
Shrinkage	£5m (in year 1)	-£4m	Yes	3 year scheme
UAG	£2m (in year 1)	£0m (no downside)	Yes	3 year scheme with increasing value
Residual balancing	£3.5m	-£3.5m	Yes	
OM utilisation	£0.27m	-£0.5m	Yes	No incentive on holding costs
Demand forecasting	£1.6m	-£1.6m	No – upside Yes – downside	Target revised to 3%
Information	£0.1m	-£0.1m	Yes	
Methane	£0.06m	-£0.06m	No	Assumes 10% over/under performance and price inc all components
Total	£12.5m	-£9.8m		

Longer term issues

3.112. We consider that there are a number of improvements to the gas incentive schemes included in our final proposals. These include the development of a three year scheme for shrinkage and the revised parameters for the residual balancing scheme.

³⁴ This column intends to give an indication of the possible payment to NGG under the schemes.

However, we consider that there are a number of areas where further improvements can be made and we will be asking NGG to look at developing proposals with respect to these areas to apply from April 2010. In particular, we consider that there would be significant benefits in developing further long term schemes.

3.113. In addition, the issues that we will also ask NGG to look into in more detail include (but are not limited to):

- The extent to which the current level of unbundling within the gas incentive scheme is appropriate;
- A review of the current arrangements regarding charging for CV Shrinkage;
- Further work regarding the development of the intra day gas linepack trading scheme;
- The interactions of scheme parameters;
- A fugitive emission scheme; and
- The possible introduction of a maintenance incentive scheme.

Appendices

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Appendix 1 - Consultation Response and Questions

1.1. Ofgem would like to hear the views of interested parties in relation to any of the issues set out in this document. 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 27 March 2009 and should be sent to gb.markets@ofgem.gov.uk for the attention of:

Ian Marlee
Director, Trading Arrangements
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. Any questions on this document should, in the first instance, be directed to Philippa Pickford or Lisa Martin (020 7901 7123). Email philippa.pickford@ofgem.gov.uk or lisa.martin@ofgem.gov.uk.

CHAPTER: One

There are no specific questions in this chapter.

CHAPTER: Two

Question 1: Do you consider that the final proposals for the SO incentive scheme to apply to NGET's external SO costs represent a fair balance of risk and reward?

Question 2: Do you consider that the proposed licence modifications appropriately reflect the final proposals as described in this chapter?

CHAPTER: Three

Question 1: Do you consider that the final proposals for the SO incentive scheme to apply to NGG's external SO costs represent a fair balance of risk and reward?

Question 2: Do you consider that the proposed licence modifications appropriately reflect the final proposals as described in this chapter?

Appendix 2 - Notice under Section 11 of the Electricity Act 1989

1.1. Please see separate document containing the notice.

Appendix 3 - Notice under Section 23 of the Gas Act 1986

1.1. Please see separate document containing the notice.

Appendix 4 - 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 Acts³⁵.

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 accordingly³⁶.

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 existing and future consumers, 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 them³⁷;
- the need to contribute to the achievement of sustainable development; and
- the interests of individuals who are disabled or chronically sick, of pensionable age, with low incomes, or residing in rural areas³⁸.

³⁵ entitled "Gas Supply" and "Electricity Supply" respectively.

³⁶ 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.

³⁷ 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.

³⁸ The Authority may have regard to other descriptions of consumers.

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

- promote efficiency and economy on the part of those licensed³⁹ 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; 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 Regulation⁴⁰ 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.

³⁹ or persons authorised by exemptions to carry on any activity.

⁴⁰ Council Regulation (EC) 1/2003

Appendix 5 - Glossary

A

Ancillary Services

Mandatory, necessary or commercial services used by the electricity System Operator to manage the system and to meet their license obligations.

B

Balancing and Settlement Code (BSC)

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

Balancing Mechanism (BM)

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

Balancing Services

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

Balancing Services Use of System charges (BSUoS)

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

Black Start

The ability to start a generating plant without external power supplies.

C

Calorific Value (CV)

The ratio of energy to volume measured in Megajoules per cubic meter (MJ/m^3) which for a gas is measured and expressed under standard conditions of temperature and pressure.

Cash out arrangements (in electricity)

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

Compressor Station

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

Connection and Use of System Code (CUSC)

Constitutes the contractual framework for connection to, and use of, National Grid's high voltage transmission system.

D

Distribution Network Operator (DNO)

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

Distribution System

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

F

Fast Reserve

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

Fast Start

The ability of a genset to ramp from standstill to its maximum rated output within five minutes of initiating a low frequency relay, or within seven minutes of a manual instruction.

Frequency Response

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

G

Gas Transporter (GT)

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

I**Income Adjusting Event (IAE)**

An event defined under the transporter or transmission licence that allows for an adjustment to be made to the relevant incentive scheme.

Intertrip

Allows for the automatic removal of a generating unit from the system usually as a result of a transmission system fault. Intertrips are required to strategically manage power flows on the system, and remove at short notice potentially vulnerable circuits.

L**Linepack**

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

N**National Transmission System (NTS)**

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

O**On the day Commodity Market (OCM)**

Enables anonymous financially cleared on the day trading between market participants.

Operating Margin (OM) (in gas)

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

Operating Margin (OM) (in electricity)

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

Own Use Gas

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

R**Reactive Power**

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

S**Sharing factors**

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

Sliding Scale

Used to describe incentive schemes which involve profit (and loss) sharing around a fixed target cost.

System Average Price (SAP)

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

System Operator (SO)

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

T**Transmission losses**

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

U**UK Continental Shelf (UKCS)**

Comprises those areas of the sea bed and subsoil beyond the territorial sea over which the UK exercises sovereign rights of exploration and exploitation of natural resources.

Appendix 6 - Feedback Questionnaire

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

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

1.2. Please send your comments to:

Andrew MacFaul

Consultation Co-ordinator

Ofgem

9 Millbank

London

SW1P 3GE

andrew.macfaul@ofgem.gov.uk