Promoting choice and value for all gas and electricity customers

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

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

Overview:

National Grid Electricity Transmission plc (NGET) is the system operator (SO) for the electricity transmission system in Great Britain (GB), and National Grid Gas plc (NGG) is the SO for the gas transportation system. This document represents the continuation of the appendices from the Initial Proposals consultation document.

The Initial Proposals document sets out our initial proposals for SO incentive schemes for NGET and NGG to apply from 1 April 2007. It invites feedback from interested parties on a number of questions set out in this document. Following consideration of respondents' views and market conditions we will develop our final proposals including statutory licence consultations for the incentive schemes. These will be published in February 2007.

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Context

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

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

Associated Documents

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

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

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

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

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

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

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

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

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

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

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

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

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Appendix 5 – October consultation responses

1.1. To assist us in developing initial proposals for the 2007/08 incentive schemes, we published a Preliminary Views consultation document on 2 October 2006 (referred to as the October consultation) in which we invited views from interested parties on the SO incentive schemes to apply to NGET an NGG from 1 April 2007.

1.2. We received thirteen responses to the October consultation document. In addition to addressing the specific questions posed by Ofgem, some parties chose to provide general comments. The views of respondents are outlined below. This section is intended to summarise the principal themes of respondents' views only and is not intended to provide a comprehensive overview of the responses received.[1]

General comments

1.3. One respondent welcomed Ofgem's early involvement of industry in the development of SO incentive scheme proposals for 2007/08 and beyond, although noting that this did mean that it could only comment in general terms as much of the detail of the schemes was still to be developed. Several parties indicated support for a longer term incentive scheme beyond 2007/08, and looked forward to seeing more detail in the Final Proposals document.

1.4. With respect to gas, respondents tended to restrict their comments to the specific questions posed in the preliminary views document, although one party expressed disappointment with the continuation of the linepack incentive.

Electricity SO Incentives

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

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

1.5. The majority of respondents supported Ofgem further investigating possible indexation of the incentivised balancing cost (IBC) target to wholesale electricity prices. Some of the reasons given in support included:

- Recent increased movements (and volatility) in wholesale electricity market prices;

1 Respondents' views can be found on the Ofgem website www.ofgem.gov.uk

- The resultant lowering of risk and the potential reduction in the need for IAEs;
- Indexation could facilitate negotiation of a multi-year incentive scheme; and
- That NGET should not profit or be penalised under the incentive scheme simply as a result of the impact of changes in wholesale market prices on balancing costs.

1.6. Most respondents indicated that only those components of IBC of which wholesale electricity prices were a key driver should be indexed, citing actions in the balancing mechanism, forward trades, frequency response, reactive power and the energy delivery component of reserve services (i.e. excluding options fees) in this category. However, a number of respondents argued that for greater simplicity, and given their 'knock-on' effect, the aggregate IBC target itself could be indexed to wholesale electricity prices.

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

1.7. Responses to the introduction of a 'price risk band' were mixed, with a number of respondents indicating they were uncertain of the objective of a 'price risk band', or that further clarity was required to assess the merits of this proposal.

1.8. Some respondents suggested that an alternative approach would be to simply adjust the IBC target retrospectively, using a 'sliding scale' based on actual wholesale electricity prices at the end of the incentive period. However, a number of respondents commented that NGET must continue to face an element of price risk, as would be the case under a 'price risk band'.

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

1.9. In terms of the current IAE provisions in NGET's transmission licence, the majority of respondents considered these were appropriate when used for unforeseen circumstances. That said a number of respondents expressed concern about how the provisions had been applied, particularly in relation to the 2005/06 incentive scheme. Information asymmetries were also regarded as a problem, meaning that IAEs were often perceived as a 'one-way' street that benefited NGET at the expense of network users.

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

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

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

1.10. Overall, and based on falling wholesale electricity prices, respondents shared Ofgem's expectations that external SO costs in 2007/08 were likely to be less than NGET's initial forecast of £483 million. Respondents also considered NGET's initial forecasts were likely to be inflated as a negotiation strategy.

1.11. Respondents found it more difficult to comment on NGET's forecast of Ancillary Services (AS) costs, particularly as some of the information had been provided to Ofgem on a confidential basis. A number expressed scepticism at the size of the increase in AS costs forecast by NGET, although one noted that based on costs incurred in the 2006/07 year to date, NGET's estimate appeared credible.

1.12. The continuing escalation of frequency response costs in particular was picked up by a number of respondents as being of particular concern. One suggested that NGET may not be instructing response in the most economical way, and that it was not always clear why particular providers were being instructed out of price order.

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

1.13. A number of respondents noted that Ofgem had recently approved CUSC Amendment Proposal (CAP) 107b and expressed optimism that this would assist in containing frequency response costs. Although one respondent noted that it may be necessary to review CAP047 if this was not the case, no respondent identified any additional amendments that might assist in placing further downward pressure on prices for AS.

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

1.14. One respondent noted the interaction between Scottish constraint costs and capital investment in the transmission system, and suggested that these be examined to ensure that longer term incentives under the SO incentive scheme and the Transmission Price Control were aligned.

1.15. Others expressed concern at the fact that NGET appeared to have limited options in alleviating certain constraints under intact network conditions in Scotland, suggesting that the bidding behaviour of companies in such a position should be closely scrutinised.

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

1.16. See question 4.

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

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

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

1.17. NGET provided extensive comments refuting the analysis and conclusions underpinning Ofgem's preliminary views on internal operating and capital cost targets for the period 2007/08 to 2001/12. No other respondent raised specific concerns with respect to Ofgem's preliminary views on the level of NGET's internal SO costs.

Gas SO Incentives

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

1.18. All respondents considered that the existing IAE provisions in NGG's transportation licence were appropriate to manage circumstances that were genuinely unforeseen at the time the scheme targets were set. A number also noted that arrangements in gas and electricity should remain consistent.

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

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

1.19. In terms of NGG's SO cost forecasts, most respondents considered these to be too high, commenting that the independent analysis undertaken by TPA on Ofgem's behalf provided a useful alternative view. A number of respondents pointed to the fact that NGG had often received the capped incentive payment for shrinkage volume as evidence that more challenging targets should be set. One respondent indicated it was difficult to provide meaningful comments on NGG and TPA's respective forecasts without additional information on NGG's historic volume performance.

1.20. A number of respondents also agreed with TPA's assessment that additional import flows in the south would reduce NGG's own use gas volumes for compression, and hence should lead to a reduction in system balancing volumes.

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

1.21. Several respondents considered that NGG's forecast appears to be overly cautious, and one party noted that in the case of Own Use Gas (OUG), the TPA counter-proposals seem credible. A number of parties considered that it was difficult to assess these forecasts without more information, but generally preferred a challenging target (ie. the low or central case). One party supported the central case on the basis that apart from unbilled energy volumes, the rationale used to forecast is less arbitrary. Another respondent considered that in respect of OUG it is reasonable to apply a significant reduction to reflect the changing pattern of deliveries of gas to the system, and that to simply apply UAG from experience unadjusted would be inappropriate.

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

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

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

1.22. Respondents tended to agree with Ofgem that NGG’s forecast appears overly cautious, and that TPA have highlighted anomalies (ie. double counting) that would support Ofgem’s preliminary views on the most appropriate basis for the system balancing gas reserve incentive scheme target.

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

1.23. See question 1.

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

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

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

1.24. Those respondents who chose to comment on internal costs generally considered Ofgem’s proposed reductions in costs to be reasonable, and several noted that the close correlation between NGG’s view and Ofgem’s view was encouraging. NGG provided extensive comments refuting the analysis and conclusions underpinning Ofgem’s preliminary views on internal operating and capital cost targets for the period 2007/08 to 2001/12.

Appendix 6 - NGET's forecast of external costs

Note: The content of this appendix is included in its entirety, as received from NGET.

1. Executive Summary

This appendix presents our forecast of Incentivised Balancing Costs (IBC) for Great Britain in 2007/8, and also includes our projection of costs for this year.

Our forecast for 2007/08 is revised down from £483m to £458m, reflecting recent falls in 2007/08 forward prices

This fall of £25m is largely driven by the reduction in forward wholesale prices for 2007/08 seen since the original forecast was prepared in July 2006. The decline in forward prices reduced our forecast by £37m: the annual forward wholesale price for 2007/08 has declined from £51/MWh at the time of our July 2006 forecast to £43/MWh at the time we completed this forecast, in October 2006[i].

This reduction has been partially offset by an increase in our constraint and Frequency Response costs within this forecast, reflecting operating experience this summer and the latest data on the 2007/08 outage programme and Frequency Response prices.

Moving from 2006/07 to 2007/08, the overall cost change is expected to be a decline of £5m

The largest forecast change in costs from 2006/07 to 2007/08 is a decline in constraint costs. 2006/07 has seen a higher level of constraint costs across Great Britain, the result of a number of different factors, and we expect costs to return to historic levels in 2007/08. However, based on current market trends we forecast some small cost rises in Ancillary services. Overall we forecast the effect of these changes is a slight decline of £5m in year-on-year balancing costs from 2006/07 to 2007/08.

Balancing costs have increased systematically between 2004/05 and 2006/07 as a result of a number of major drivers

[i] See Section 4 for full discussion of prices used in this forecast. In particular, the forward wholesales price for winter 2007/08 has declined from £58/MWh to £48/MWh.

Summary of IBC, 2004/5 to 2007/8

Year	2004/5	2005/6	2006/7	2007/8
IBC (£m)	290.6	427.5	462.7[ii]	457.9

N.B. Table includes actual and forecast data

The greatest impact of these rises can be seen in the increase in costs between 2004/5 and 2006/7. Costs over this period have risen from £290.6m (2004/5 outturn)[iii] to a projected figure of £462.7m for 2006/7[iv].

The systematic increase in balancing costs seen since between 2004/05 and 2006/07has been driven by three major factors:

- Increases in wholesale electricity and generation fuel prices;
- BETTA, and in particular Scottish constraint costs;
- The introduction of CAP047.

The changes in costs from 2005/06 to 2007/08 are discussed in full detail in section 11, below.

This appendix presents next year's forecast, constructed from the bottom-up. Despite the relatively small change in headline figure, there are a number of detailed cost changes within the forecast, reflecting forecast price and volume changes, small changes in market drivers and anticipated adjustments to the balance of BM and Ancillary costs as a result of economic procurement decisions.

Overall, we forecast that next year's costs will in fact fall below this year's current projection. We still face a number of uncertainties with regard to forecasting next year's costs. Most significant amongst these are the evolution of 'winter' balancing costs following the high levels seen last winter.

In addition, we face uncertainty regarding the evolution in power prices and, separately, trends in several key Ancillary Service costs. These are:

- Continued evolution of Frequency Response Holding prices, in particular following the introduction of CAP107 changes on 28th December 2006.

[ii] See 'Stop Press' at the end of this appendix. Our current projection has increased to £480.9m.
[iii] Note that an equivalent basis means that we have corrected 2004/5 figures to remove the notional cost of transmission losses. Actual outturn figures for 2004/5 are £384.1m; to calculate a figure for 2004/05 on the same basis as 2005/06 onwards, £93.5m of gross transmission losses is removed.
[iv] Note that here, and throughout this Appendix, we quote historic IBC on a basis before Income Adjusting Events ('IAEs').

- Changes in commercial frameworks resulting from ameliorations to two balancing services. BM Start-Up was introduced to replace the old 'Warming' service on 2nd November 2006. Short Term Operating Reserve (STOR) will replace the Standing Reserve and Supplemental Standing Reserve from 1st April 2007. We shall receive the first tenders for this new service in January 2007.

Whilst we anticipate longer-run benefits from these changes in terms of efficiency and economy, in some cases these services will take time to roll out to all providers, and in all cases will naturally take time to 'bed in'. Furthermore, we anticipate that there may be initially some price exploration within these new markets. As a result we have forecast a limited to neutral effect for this first year. However, we will look to provide updates to Ofgem as more data becomes available through the winter and in particular in January 2007.

Overall our forecast suggests that all the major changes in balancing costs have already occurred, from last year to this year, and hence the forecast onto next year is simpler by comparison. As described above, where uncertainty exists we will continue to update Ofgem as new information becomes available.

2. Introduction and Assumptions

This forecast has been prepared by our normal forecasting process. This appendix begins by explaining the forecast method, and then looks at the historic performance of the drivers of IBC and the possible range of values for these drivers for 2007/8, based on recent experience. The appendix then discusses each element of the forecast, before presenting the overall forecast of GB incentivised balancing costs for 2007/8.

We assume in our forecasts that:

- In line with Ofgem's Preliminary views document[v], the general scope and form of the incentive scheme remains the same for 2007/8 as in 2005/6;
- The impact of BSC modifications or CUSC amendments, beyond those already approved by October 2006, is not considered[vi];
- There is no inclusion of costs resulting from the implementation of CAP048 (Firm Access and Temporary Physical Disconnection) or CAP070 (Short Term Firm Access).

[v] http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/16920_179_06.pdf
[vi] For the avoidance of doubt, CAP107b approved on 28 September 2006 and due to be implemented on 28 December 2006 has been factored into our forecast of Mandatory Frequency Response Costs for 2007/8

3. Construction of Forecast

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

IBC = CSOBM – NIA[vii] + BSCC + TLA[viii]

where

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

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

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

where

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

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

We have simplified our approach to forecast drivers for 2007/8 and focussed only on those drivers that are currently active. Therefore, in developing the forecast we have considered the following key drivers to have the greatest effect on overall balancing cost:

- Forward wholesale electricity prices;
- BM Prices – average accepted BM bid and offer prices;

[vii] NIA here is defined as NIV×NIRP, where NIV=-TQEI. Thus, this is the opposite sign convention from the licence definition, which is TQEI×NIRP.

[viii] The Formal Licence definition includes the terms OM and RT, which are both forecast to be £0 for 2006/7 and 2007/8.

- Net Imbalance Volume (NIV) or Market Length;
- Free Headroom – the level of part-loaded plant delivered by the market at gate closure.

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

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

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

The effects of Scotland to England and Anglo-French flows are considered separately within the constraint forecast and Transmission Losses forecast. Plant margin is not considered to be a major driver of costs for 2007/8, as sufficient plant margin is expected to be available (over 20%).

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

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

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

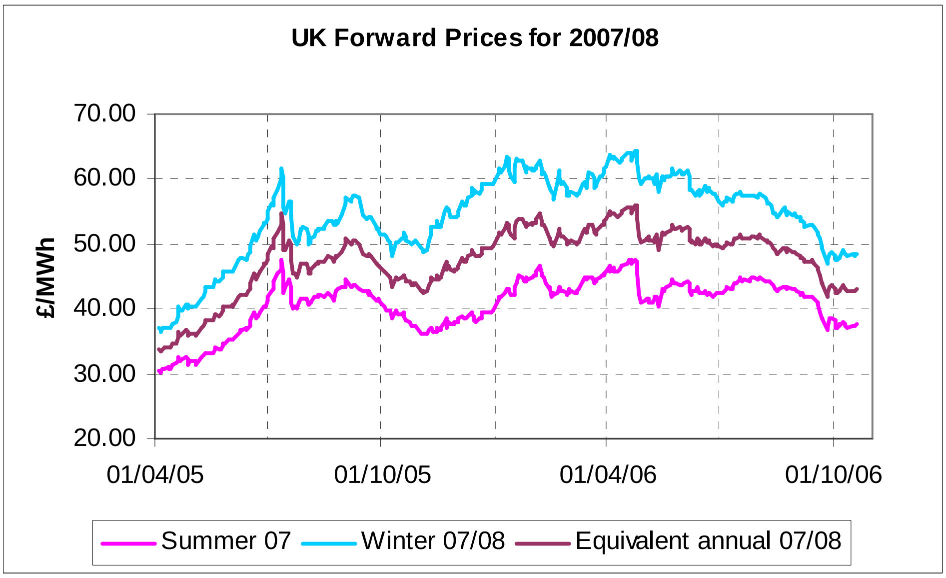
The historical and future performance of the above key cost drivers are described in the following section.

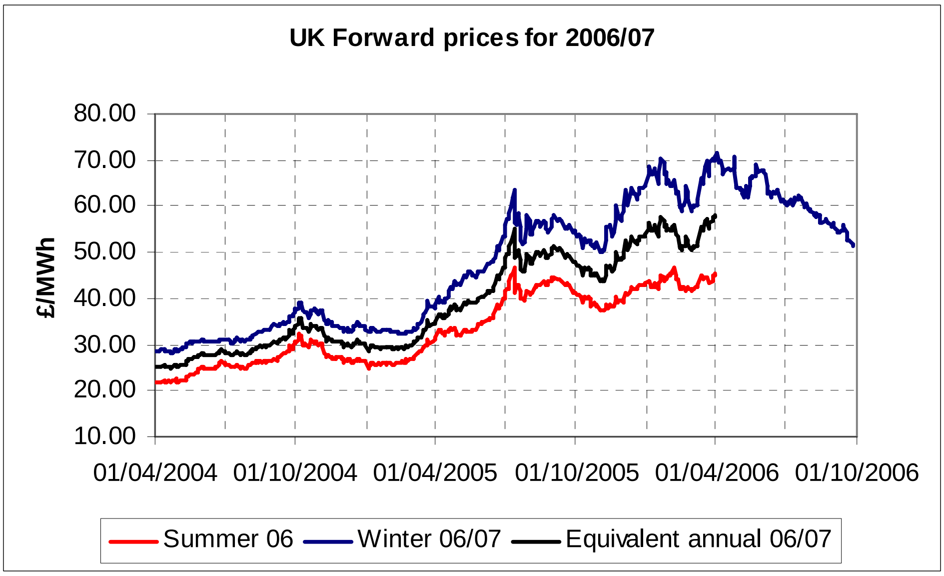
4. Balancing Cost Drivers

Electricity Forward Price

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

Over Financial Year 2005/6 the forward price of electricity for summer 2007 and winter 2007/8 increased markedly, in line with other forward prices. Summer 2007 rose 50%, Winter 2007/8 by 70%. However since April 2006, the forward prices have fallen, and the 2007/8 season prices have declined by 20%. The key factor behind these movements is the forward wholesale price for gas.





Summer 2007 baseload has remained in the range between £35/MWh and £50/MWh since July 2005, and in mid-October 2006 was in the lower end of this range. The winter 2007/8 baseload forward price remained almost entirely in the range of £50/MWh to £65/MWh from July 2005 to September 2006, when it fell below £50/MWh. By mid-October 2006, the 2007/8 season prices were sitting at roughly the same levels as they had been a year previously.

The average baseload forward price for 2007/8, the current price at the time of the forecast was £43/MWh[ix].

Balancing Mechanism Prices

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

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

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

The BM Bid market is competitive, with a large volume of bids accepted by National Grid principally for energy balancing[x]. In contrast, the average accepted BM Offer price is more volatile from month to month. Our analysis suggests this is because the volume of offers taken is smaller than the volume of bids and is more closely associated with balancing actions taken to create Operating margin or to resolve system constraints and is therefore more volatile than the more, 'liquid' average bid price.

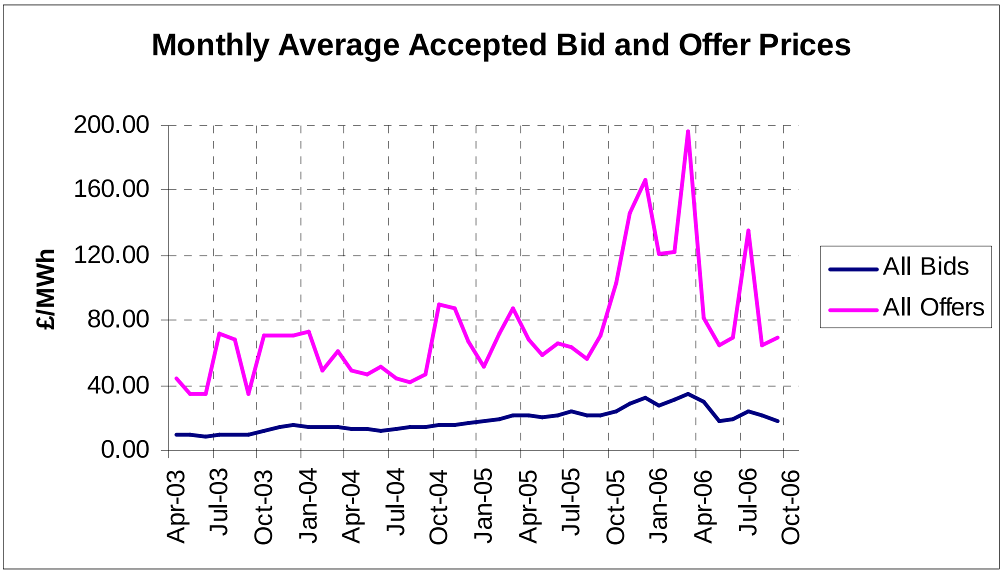
The first graph below shows the rise in Bid and Offer prices over 2005/6 driven by rises in generation costs, linked to wholesale gas price rises. Over this period, the bid and offer prices shown in the graph were on average 65% higher than a year previously. Although prices appear to have dropped off from April 2006, this is a winter/summer effect. In fact prices shown for the first half of 2006/7 have been the same (bids) or 30% higher (offers) as a year previously. Significant peaks are seen in BM offer prices during winter 2005/6 and July 2006.

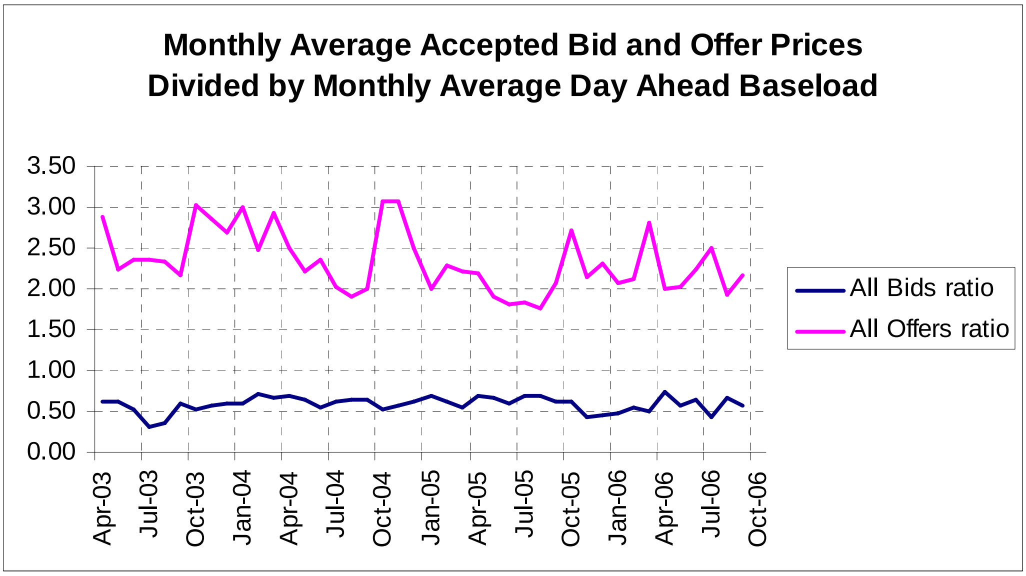
The second graph below shows that, despite rises in prevailing prices, the relationship between BM Bid and Offer prices and forward wholesale electricity prices has been more stable.

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

As discussed above, the ratio of Offer price to forward wholesale electricity price is more volatile, varying between approximately 1.7 and 3.1 over the past three-and-a-half years. However the ratio is sufficiently stable to give forecasting confidence.

[ix] Argus data, quote date 20th October 2006.
[x] By 'energy balancing' we mean here the resolution of the energy imbalance in the market, equal to the net imbalance volume, NIV.





Net Imbalance Volume (NIV)

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

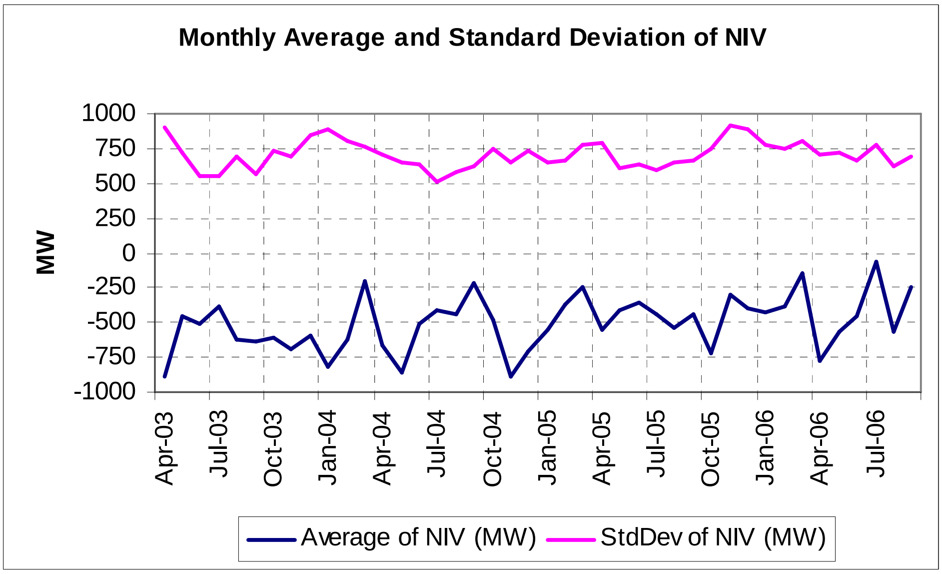
NIV directly determines the volume, and hence the costs, of Bids and Offers which National Grid has to take to balance the market. It also affects the amount of operating margin available to us from the market at Gate Closure because any headroom provided by a long market (negative NIV) provides Reserve that can be used by National Grid to balance the system. Likewise, a short market, as is often seen over the peak of the day, means that National Grid must take additional actions to meet demand and Operating Margin.

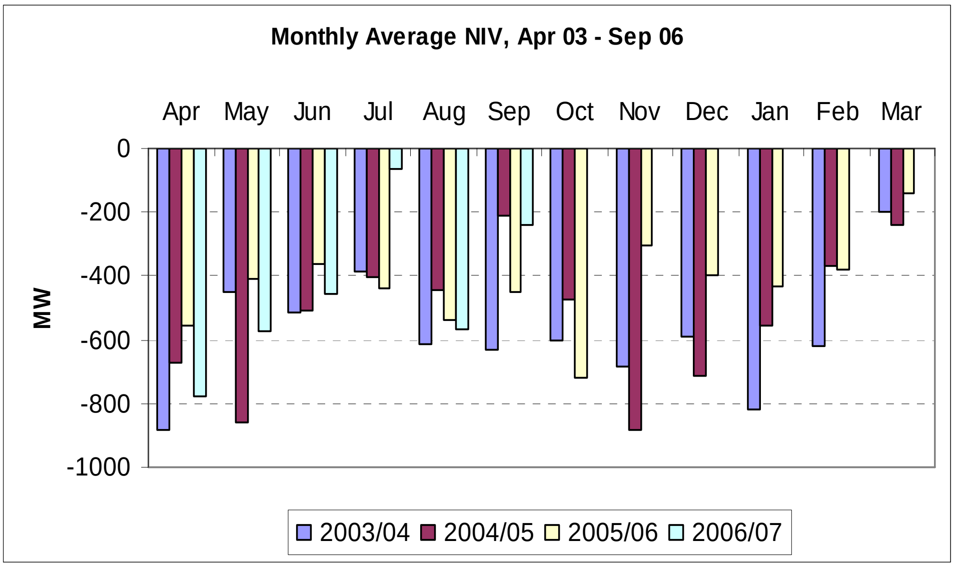
NIV is the cumulative imbalance of the market as a whole and depends upon a number of factors, but on average is mainly affected by the actions and policies of suppliers, for example their:

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

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

It can be seen from the graphs below that average NIV became less negative over winter 2005/6, perhaps as a result of higher wholesale electricity prices. NIV averaged -430MW (long) in 2005/6, some 100MW less long than the previous year, and has since averaged to a comparable level. Over 2005/6 and the first half of 2006/7, the standard deviation of NIV has remained in line with historic trends.



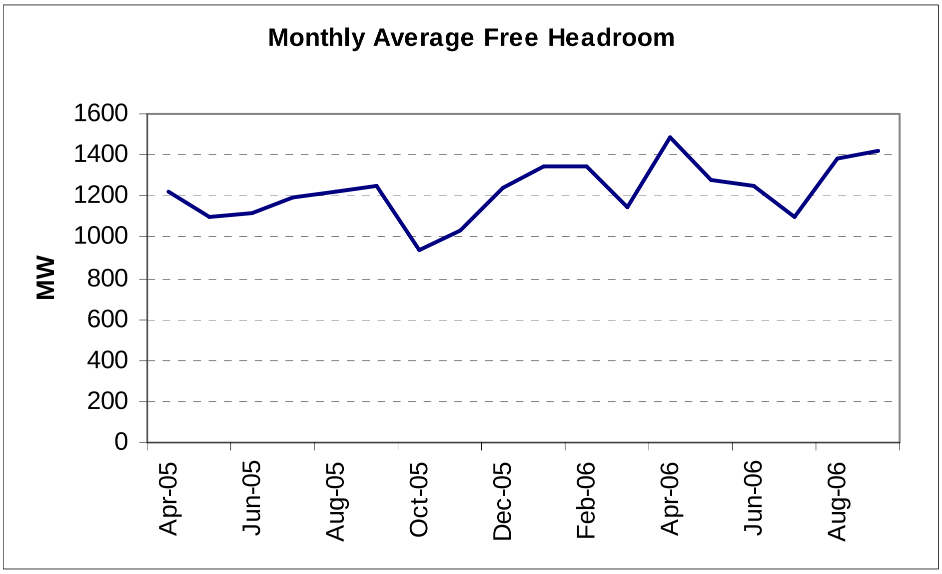


Free Headroom

Free Headroom provides Operating Margin to National Grid that can be used to balance the system. A decline in Free Headroom results in additional actions being taken by National Grid to create and maintain Operating Margin. A number of new elements have made the calculation of historic free headroom more complex than in previous years, these include:

- Sterilisation of Free Headroom behind export constraints, particularly in Scotland;
- Unavailability of apparent free headroom on plant such as Cascade Hydro and Wind (in certain specific cases, due to an inability to generate up to the maximum level declared available in the BM).

The graph below shows monthly average Free Headroom at the demand peak has increased slightly following BETTA Go-live. Previously headroom had been on a downward trend since NETA Go-live. This rise in free headroom has been counteracted by a reduction in NIV over the same period.



5. Scenarios – forecast range of drivers of balancing costs

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

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

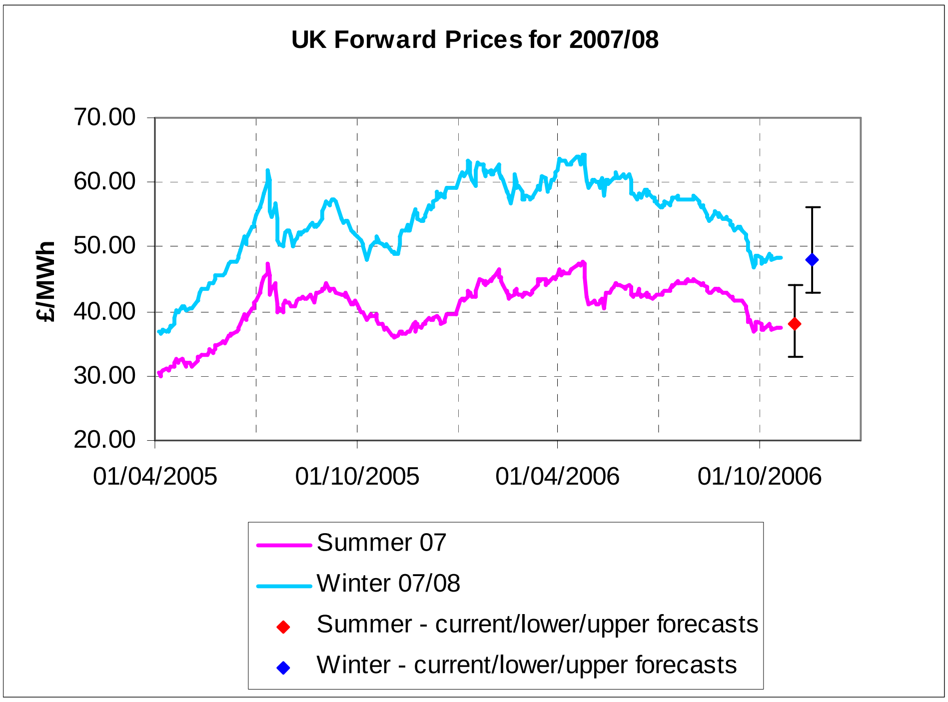
Forward Price Assumptions

Our current, and thus mid view, of power price is taken direct from the prices in the market (as of Friday 20 October 2006).

The upper and lower cases are based on National Grid's best view of possible high and low outturns. Compared with the mid view, these are +6 / -5 £/MWh for summer 2007, and + 8 / -5 £/MWh for winter 2007/08.

Case	Summer	Winter
Upper	£44/MWh	£ 56/MWh
Lower	£33/MWh	£ 43/MWh
Current	£38/MWh	£48/MWh

The graph below shows these forecasts together with historically-quoted prices.



BM Price Forecast Assumptions

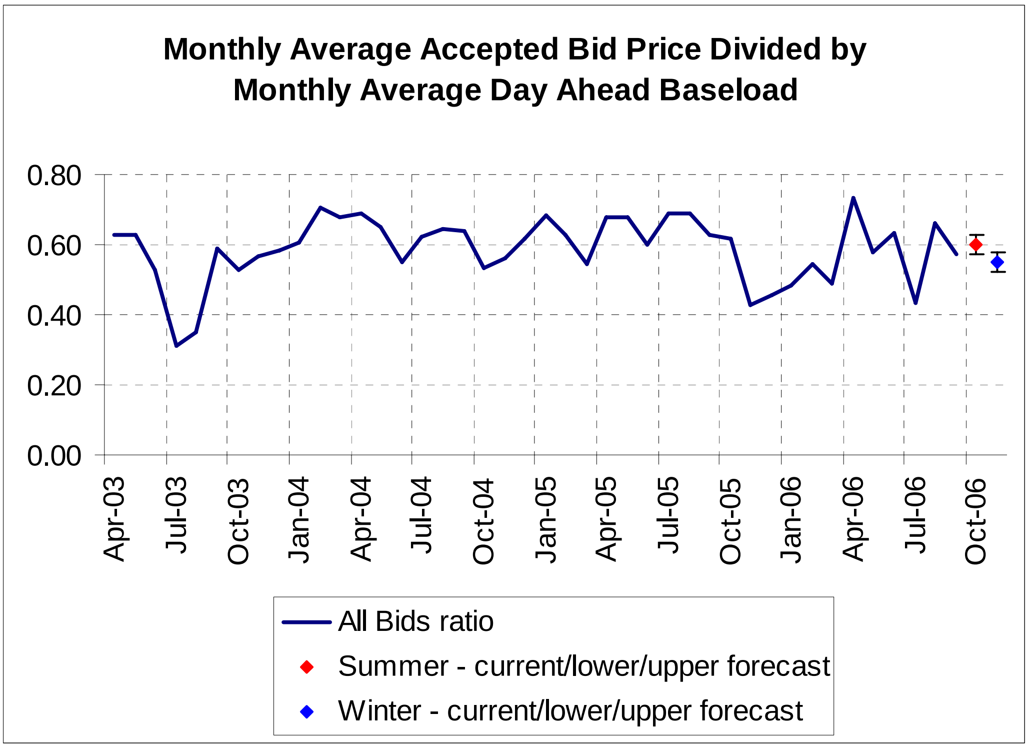
We have forecast the likely range of BM prices based on the historically observed ratio of BM prices to wholesale prices discussed above. To calculate the possible range of annual average ratio we have used the maximum and minimum value of the rolling month average, as shown below. It is clear that the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

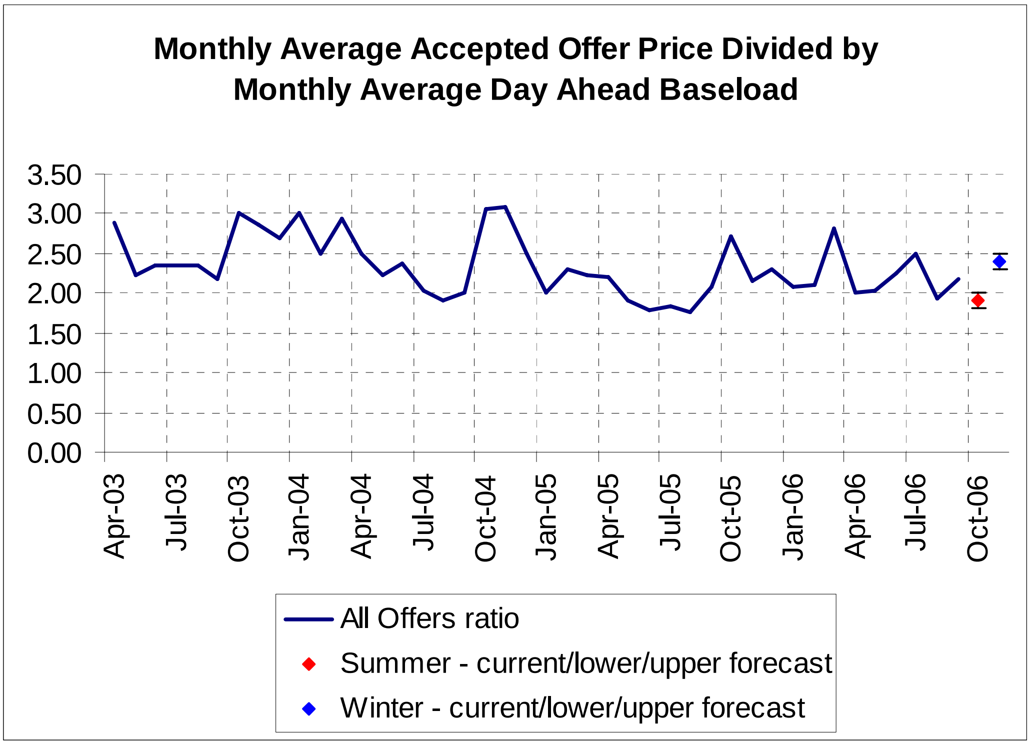
For our forecast we have assumed there is no change in Bid/Offer ratios to the average of the 12 monthly values for 2005/06, namely 0.58 and 2.15. These are split into summer and winter values: for bids, 0.60 and 0.55 respectively; for offers, 1.9 and 2.4. Upper and lower cases have then been taken as roughly +/- 5%. These are shown in the table below:

Case	Bids	Offers
	summer : winter	summer : winter
Upper	0.57 : 0.52	2.0 : 2.5
Lower	0.63 : 0.58	1.8 : 2.3
Current	0.60 : 0.55	1.9 : 2.4

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

The graphs below show these forecasts together with historic outturns.



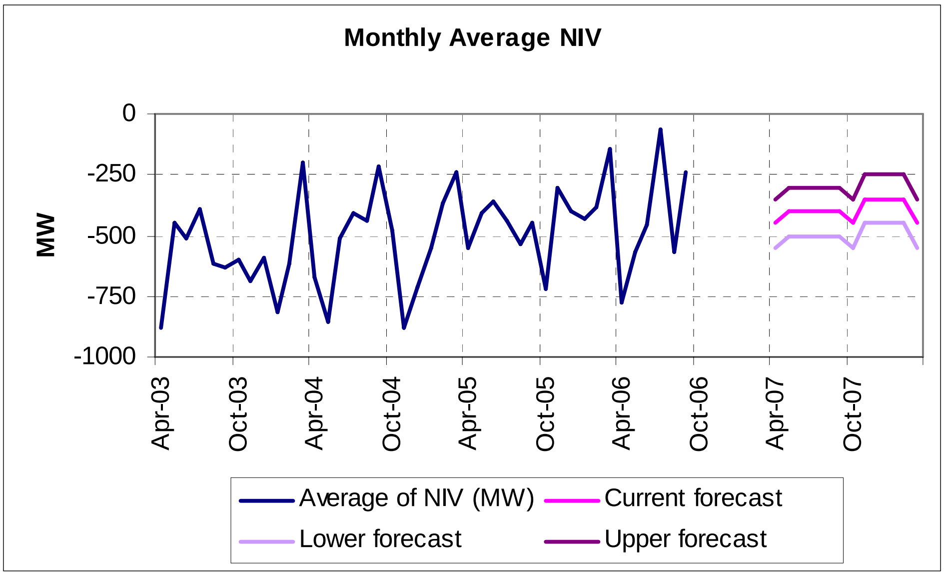


NIV and Headroom Forecast Assumptions

Average NIV has become slightly less negative (more balanced) over the last two financial years and we forecast this trend will continue in 2007/08. Our mid view is a slightly less long average NIV of ~-400MW. Upper and lower cases are +/-100MW.

For forecasting purposes the year is split into three parts: Summer (May to September), Equinox (March, April and October) and Winter (November to February). As for other drivers, we adopt a different forecast value for NIV in each of these forecasting seasons, as shown in the table and graph below.

Case	NIV
	summer : equinox : winter
Upper	-300MW : -350MW : -250MW
Lower	-500MW : -550MW : -450MW
Current	-400MW : -450MW : -350MW



Our forecast for free headroom change is a continuation of the slight rise seen in 2005/06 and since. We assume for 2007/08 an increase of ~100MW compared with 2005/06 outturns. For simplicity, this is adopted for all mid, upper and lower cases.

6. Scenario Parameters

The table below summarises the scenario parameters used in our forecast model. [xi]

[xi] In the scenario parameters table, the values of Free Headroom are higher than shown in the earlier graph of recent outturn headroom. This is because the forecast model was developed using a different measure for headroom to that shown in the graph. However for forecast purposes, it is the change in the measure from one year to the next that is important, which will be similar for both benchmarks.

Forecast year: 2007/8				Scenario			
				1 Low	2 Central	3 High	Mean
Driver of IBC		Outturn 2005/06	Outturn 14Mar05 - 13Mar06	20%	60%	20%	
Forward Prices	Sum	32.5 £/MWh	32.5 £/MWh	£33	£38	£44	£38
	Equ	43.0 £/MWh	37.2 £/MWh	£40	£45	£53	£45
	Win	54.0 £/MWh	54.1 £/MWh	£43	£48	£58	£49
	Annual	42 £/MWh	41 £/MWh	£38	£43	£51	£44
Offer Prices (£/MWh)	Sum	63 £/MWh	61 £/MWh	£59	£72	£88	£73
	Equ	133 £/MWh	100 £/MWh	£83	£98	£123	£100
	Win	141 £/MWh	138 £/MWh	£99	£115	£145	£118
	Annual	102 £/MWh	93 £/MWh	£79	£93	£116	£95
Bid Prices (£/MWh)	Sum	22 £/MWh	23 £/MWh	£21	£23	£25	£23
	Equ	26 £/MWh	24 £/MWh	£23	£25	£28	£25
	Win	30 £/MWh	31 £/MWh	£25	£26	£30	£27
	Annual	26 £/MWh	26 £/MWh	£23	£24	£27	£25
NIV (MW)	Sum	-440 MW	-426 MW	-500	-400	-300	-400
	Equ	-470 MW	-521 MW	-550	-450	-350	-450
	Win	-380 MW	-372 MW	-450	-350	-250	-350
	Annual	-428 MW	-432 MW	-496	-396	-296	-396
Free Headroom (Daytime) (MW)	Sum	1500 MW	1503 MW	1600	1600	1600	1600
	Equ	1500 MW	1385 MW	1500	1500	1500	1500
	Win	2200 MW	2191 MW	2300	2300	2300	2300
	Annual	1725 MW	1718 MW	1808	1808	1808	1808

6. Ancillary Costs

Methodology

Historical costs and volumes of Ancillary Services (AS) are reported in our Monthly Balancing Services Statements, and extensively to Ofgem, in particular as part of Ofgem's monitoring of our balancing activity during 2006/7. Our AS forecast model is consistent with this reporting, and with the approach adopted for other components of IBC.

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

Frequency Response

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

Prices have been submitted monthly under the current pricing arrangements since November 2005. Average accepted prices for mandatory Frequency Response are shown in the graph below. Significant additional detail on recent Frequency Response costs can be found within our Income Adjusting Event notice in relation to CAP047[xii]. The latest response price and utilisation data can be found on our Industry Information website, within the balancing services section.

Up to October 2006, both average submitted and average accepted prices have followed a sustained upward trend, at an approximate average increase of 7% per month. Additionally, a growing number of BMUs are priced at levels suggesting they prefer not to provide this service.

At present, the drivers for observed changes (increases) in Mandatory Frequency Response since the introduction of CAP047 do not appear to be explained by any underlying market characteristic that one may expect in a stable sustainable market place. It remains unclear to us whether this market will stabilise in future given the issues and concerns highlighted previously and in particular during CAP047 considerations.

We have considered the following drivers, but have not identified an underlying economic rationale for the increases:

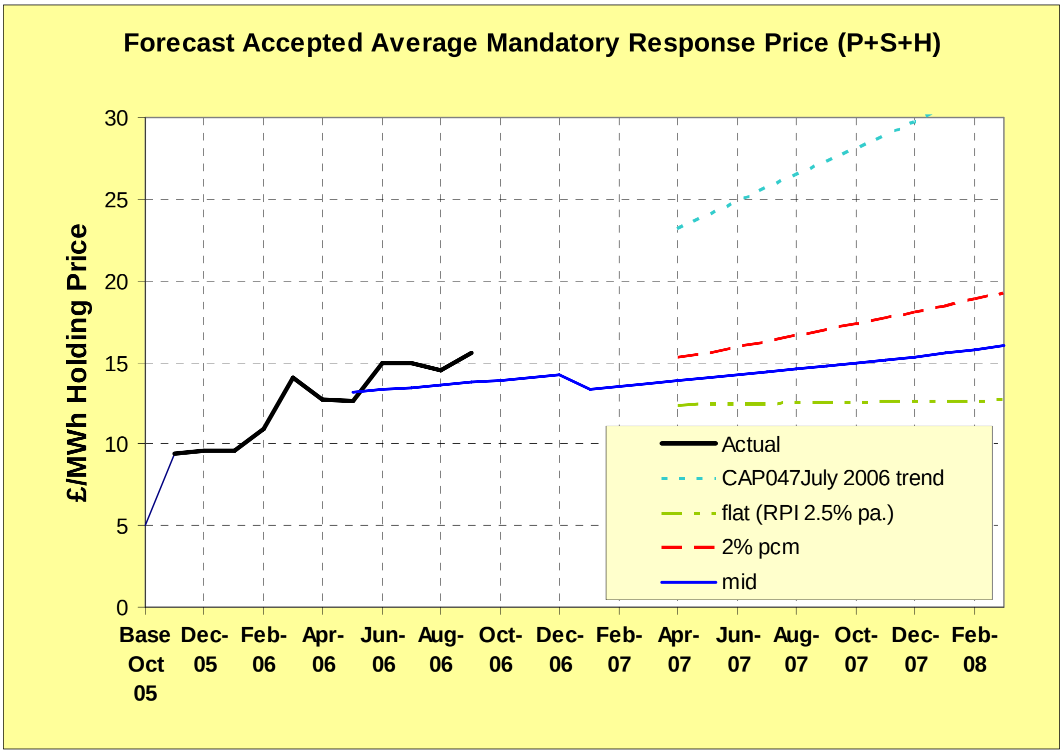
- If prices had been driven by fuel cost (or expected fuel cost, because prices are submitted in advance), then we would expect to have observed a sharp price increase, particularly for gas-fired generation, during the winter and then these prices to have reduced during the summer, reflecting trends in fuel costs. This has not occurred.
- If the main driver for the increase had been a systematic under-recovery of the true costs of response holding under the old mechanism, then we would expect to have observed a sharp step change immediately following the introduction of CAP047, followed by little movement in prices. Again, the observed sustained increase goes against this hypothesis.
- Also related to under-recovery, if the main driver for the price increase had been a systematic under-recovery of the costs of Response Energy, related to CAP107, we would expect to have observed a decline in price during the summer, as the cost of Response Energy provision reduced. This has not occurred.
- Sustained price increases could also be explained if National Grid had significantly increased the volume of Mandatory Response procured over the same period. However, the volume of Mandatory Response procured by National Grid has remained broadly comparable over the period November 2005 to July 2006.

It is important to note that whilst we do not consider any of the above effects to be the major driver, the price trend observed may be the result of the combination of a number of drivers, including several of those discussed above. Given the absence of a clear cause, it remains probable that some of the price increase relates to price exploration in what remains a relatively new market. We will continue to analyse these price trends, and it is likely that our view on

[xii] This document is available via the following hyperlink:
http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/15626_1c.pdf

future prices will change as prices mature, particularly following the introduction of CAP107 in late December 2006.

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



Our full forecast of Frequency Response costs has been provided separately to Ofgem. Overall, based on a mid-range price increase of 1% per month and a price reduction for CAP107b (from January 2007) of £1.08/MWh, we forecast £107.5m for response cost in 2006/7.

Our forecast for 2007/8 continues to assume a 1% per month price increase and costs increase to £114.2m 2007/8. As can be seen from the graph above, as of September 2006 prevailing prices remained above the majority of months of our forecast for 2007/8.

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

Reactive Power

The volume of reactive power utilised during 2005/6 outturned at 26.8TVarh with the inclusion of Scottish MVarh which are now paid under GB CUSC arrangements. We forecast no change in the total volume of GB reactive next year. We expect the upward drivers of increased Wind generation and demand growth to be offset by despatch efficiencies, as we gain increasing experience of the Scottish system.

Following the implementation of CUSC amendment CAP045, the price of default reactive utilisation is 50% indexed to power prices. Our forecast for Reactive Power costs is therefore based on a straight calculation of prices based on our forecast of power prices. Tenders seeking reactive market contracts factor in the full default price into their tendered prices, and therefore our forecast is not sensitive to assumptions of the number of tenders accepted.

The consequence of our views of a static year-on-year volume, and the relatively small movement in forecast power price 2007/8 on 2005/6, results in our forecast of reactive costs staying very stable from £55m last year to £54m next year.

Standing Reserve

For 2006/7, we have contracted a volume of 2,456MW of Standing Reserve, plus 742MW of Supplemental Standing Reserve, at a total projected cost of £61.6m. This cost comprises £56m of availability fees, plus £6m of utilisation payments to non BM providers paid via Ancillary Service contract payments.

For 2007/8, based on our procurement expectations we are forecasting a rise in expenditure to £69m. As this forecast is to be published ahead of the submission of Standing Reserve tenders under the new STORT process in January 2007 ('Short Term Operating Reserve Tenders'), we do not consider it would be appropriate to comment further on the construction of this forecast cost. However, this forecast is consistent with our BM forecast in that any additional volume procurement under STORT in 2007/8 will reduce BM cost by at least an equivalent amount. In addition, our forecast is consistent with the best market indicators of likely tendered prices. We have separately provided full details of this forecast to Ofgem.

Fast Reserve

Costs for Ancillary Fast Reserve for 2006/7, across firm and optional sources, are projected to outturn at £40.8m. We forecast no changes to the volumes of services being bought, or to the prices paid, which reflect the current degree of competition in this market; accordingly our forecast for Ancillary Fast Reserve costs for 2007/8 is £41.0m.

Other Reserve

Within Ancillary in 2006/7, we project to spend £6.4m on other reserve services, such as Fast Start payments to OCGTs and pumped storage, which do not fit into the above categories. We forecast to spend £6.5m on Ancillary Other Reserve for 2007/8.

BM Start-Up costs

The cost of warming contracts outturned at £7.4m for 2005/6. This is much lower than historic levels of £15-30m for Warming costs. The reduction is due in part to the increase in dispatch of CCGT stations through PGBTs and in the BM, rather than through Warming contracts, and also increased synchronisations of warmed machines by National Grid.

For 2007/8, we anticipate a similar volume and price of activities by current providers. However, we anticipate that the introduction of firm payment provisions as part of the roll-out of new BM Start-Up service will result in a transfer of £5m of costs from BM margin acceptances into increased Ancillary payments (formerly termed Warming) under the new provisions. This £5m has been explicitly factored out of our BM forecast. Therefore, our 2007/8 forecast is £12m.

Black Start

Costs for Black Start services for GB are projected at £16.0m for this year, and include the costs of Scottish providers, and refurbishment and testing of some existing providers. We observe that two new services, which commence partway through this year, will achieve a full year of operation next year, and also that an increased number of existing service providers are looking to undertake refurbishments next year. Accordingly, we forecast a rise in Black Start costs for 2007/8 of £17.7m.

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

Constraints

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

SO-SO Energy

The costs of ‘SO to SO trades’ across the French and Moyle Links, outturned at £12.0m in 2005/6. These costs interact strongly with costs both pre-Gate in the BM for Constraints, Margin and Footroom amongst others. For simplicity in this forecast, we preserve this cost of £12m in all future years. Variations in the costs of this service are handled by the driver impact on BM costs, analysed in the preceding sections.

Ancillary Other

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

Total Ancillary Forecast

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

The table shows the historic costs of each service for 2005/6, the projected costs for 2006/7, and our forecast for 2007/8.

Summary of Forecast Ancillary' Costs for 2006/7 and 2007/8 (£m)

	2005/06	2006/07	2007/08	Variance to 2006/7
Reactive	54.7	55.3	54.3	-1.0
Response	65.4	107.5	114.2	6.7
Fast Reserve	36.6	40.8	41.0	0.2
Standing Reserve	42.2	61.6	69.2	7.6
Other Reserve	6.3	6.4	6.5	0.1
Warming	7.4	8.6	12.0	3.4
Black Start	14.5	16.0	17.7	1.7
AS Other	1.0	1.6	2.0	0.4
Total	**228.1**	**297.8**	**316.9**	**19.1**

It can be seen that the main cost rise is from 2005/6 to 2006/7, reflecting services we have already contracted for this year. The progression to 2007/8 shows continuing cost rises in Response and Standing Reserve.

7. Constraint Costs

Forecasting Approach

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

- Cheviot boundary (between Scotland and England);
- Within Scotland;
- England & Wales.

For the Cheviot boundary, we use a probabilistic model, which convolves distributions of Scottish generation against demand level and Cheviot boundary flows against the boundary's capability.

Because of the multiplicity of possible constraint boundaries, such a model is not feasible to forecast constraint costs in England & Wales or within-Scotland. The approach used is bottom-up, involving:

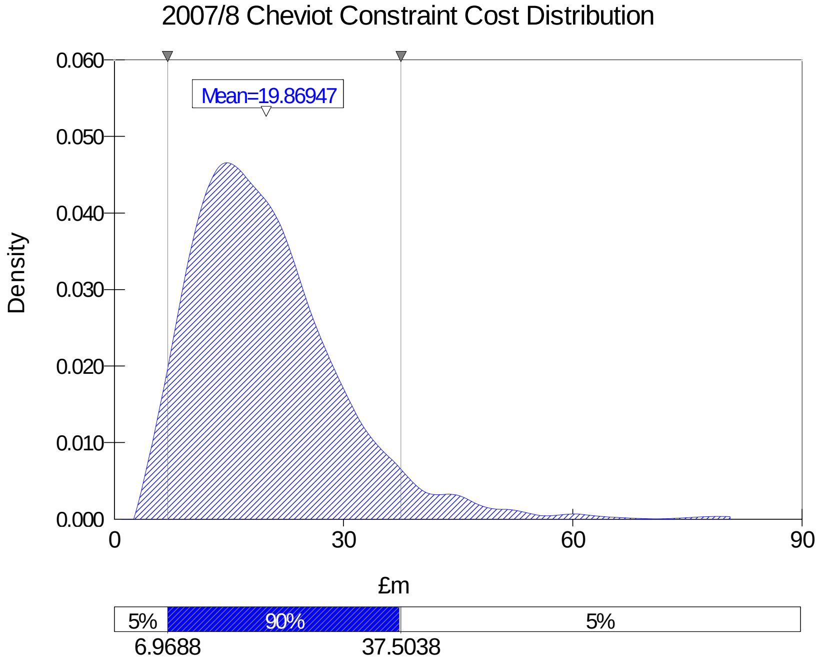
- Detailed studies of the transmission network, based on planned transmission and generator outages, and on utilisation of short term circuit ratings and operational measures;
- Uncertainties in market behaviour, such as French interconnector flows, are studied and the impact estimated;
- Key outages and/or transmission boundaries that cause significant constraint costs are identified, taking into account mitigating measures that may be available in operating time scales, such as shifting or shortening of outages;
- The risk and impact of plant closures are studied and estimated;
- All constraint forecasts are reviewed and challenged by experts within National Grid.

Cheviot (Scotland to England boundary)

We have re-run our Cheviot forecast model for 2007/8. The model has been calibrated, such that against 2005/6 data it yields 300GWh of constrained energy with an outturn cost of £30m, in line with the historic outturn. For 2007/8, key assumptions are:

- 12 circuit-weeks of Cheviot outage, as planned for summer 2007;
- Cheviot boundary limits calibrated to 2005/6 actual average capability of 2096MW winter, 1874MW summer-intact, and to 1390MW summer-outage, in line with experience;
- Power prices and Bid / Offer prices reflect those identified in our Scenario parameters;
- Scottish generation profiles that reflect historical trends and anticipated plant outages;
- 1,270MW:1,590MW of Wind capacity installed summer : winter. (There was already 760MW of capacity installed as of March 2006, and we only assume that 510MW of 700MW projected projects complete by March 2007, in line with projects that are actively progressing with construction etc.).

Against these assumptions, and including mitigations such as the availability of some intertripping services across the Cheviot boundary, our model forecasts a total Cheviot cost of £19.9m. The P90 range of the overall cost is from £7.0m to £37.5m with the mean of £19.9m, as shown in the distribution below.



The model reports 230GWh constrained energy resolved by Intertrip, plus 140GWh constrained energy resolved in the BM, giving a total constrained energy forecast of 370GWh for 2007/8 (cf. 300GWh in 2005/6 outturn). The increase reflects our modest assumptions of new Wind commissioning in Scotland.

Within Scotland

This year as last year, we have experienced a number of constraints within both the SHETL and SPTL[xiii] transmission systems, both import and export constraints. We have identified at least eight distinct constraint boundaries as causing costs. Mainly these constraints occur under conditions of transmission outage, but some occur for an intact network, and/or under unusual combinations of generation.

Whereas constraint costs within Scotland outturned at £28.5m for 2005/6, this year we have experienced a more onerous transmission outage programme, and more adverse conditions of Scottish generation volume and pricing. We project within-Scotland constraint costs to outturn at £44m for 2006/7.

[xiii] Scottish Hydro Electric Transmission Limited, SHETL, and Scottish Power Transmission Limited, SPTL

Next year, the transmission outage programme, across the two most expensive constraint boundaries is currently planned to be less onerous than it has been this year. Accordingly, we are able to forecast a reduction in within Scotland constraints, of £5m, to £39m.

England & Wales

England & Wales constraints outturned at £19.6m in 2005/6. We monitor costs against over twenty constraint groups, and in contrast to earlier years post-NETA, we are seeing a number of export constraints, in addition to the import constraints which dominated E&W constraint costs over 2001–2004.

For this year, we have suffered some adverse circumstances in relation to unplanned transmission outages coincident with planned transmission outages. We project the England & Wales constraint cost to outturn at £29.0m this year.

Next year, the transmission outage programme is less onerous for a number, but not all, of our E&W constraint boundaries. Accordingly, our bottom-up forecast by constraint boundary summates to a forecast of £22.0m for England & Wales constraints in 2007/8. This is nearer the level of 2005/6, than the level we are seeing this year.

The rise in E&W constraint costs from a historic low level of £10–15m seen in 2001 2002 and 2004, to levels of £20–30m pa currently is primarily caused by the rise in energy price, which drives BM prices, and the increase in transmission outages. Over the past few years and moving forwards, National Grid continues to increase the level of capital expenditure to deliver essential asset replacement and refurbishment work on our system to maintain levels of performance and reliability. In doing this, we will increase the number of lengthy construction outages on our system, and this will inevitably increase constraint costs. In 2007/8, we face several long outages for asset refurbishment, which cause significant and unavoidable constraint risks.

Summary of GB Constraint Forecast

The table below summarises the total forecast of GB constraint costs.

Forecast GB Constraint Costs for 2007/8 (£m)

	2005/6	2006/7	2007/8
Cheviot Boundary	31.6	20.3	19.9
England & Wales	19.6	29.0	22.0
Within Scotland	28.5	43.9	39.0
GB Total	79.7	93.2	80.9

In summary, we forecast a mean GB constraint cost of £80.9m. Overall, this cost returns from a high level for this year, towards the level for last year.

We have not explicitly forecast a range of GB constraint costs, because the scenario parameters do not clearly interact with the bottom-up process for estimating within-Scotland and England &

Wales constraint risks. However, the chart above illustrates the variability possible across the Cheviot boundary, and this, together with our views of the variability of other constraint costs, contributes to the forecast GB IBC distribution shown later.

8. Transmission Losses Forecast

Methodology

As in previous years, our GB transmission losses (TL) model is based upon forecast changes in the zonal disposition of generation, since our observations of past years suggest that this is the most significant driver of losses volumes. The difference between historical and forecast station output for each zone is multiplied by the Transmission Loss Factor to give the forecast change in zonal TL. Thus, forecast TL is calculated as base period TL plus the sum of forecast zonal TL changes.

Under the net losses scheme, the volume term within TLA (Transmission Loss Adjustment) is now set to be {TL - TLT}, the outturn volume of TL minus the Licence target TLT. The total forecast TLA then equals the product of {forecast TL - TLT} and the reference price TLRP. TLRP is assumed for the purposes of this forecast to be £43/MWh – the current forward price for 2007/8 (although as per Ofgem's preliminary views, it is possible that we will move to a variable transmission losses price); TLRP has remained at £29/MWh for 2005/6 and for 2006/7.

$$\text{TLA fcst} = \{ \text{TL fcst} - \text{TLT} \} \times \text{TLRP}$$

Base Data

The base period used for the forecast is October 2005 to September 2006, in which GB losses totalled 5.778TWh. For comparison, GB losses over the first year of BETTA 2005/6 totalled 5.601TWh, and we ascribe the increase of 0.177TWh, summer 2006 on summer 2005, to greater flows from Scotland to England then.

Forecast

The table below shows
- actuals for 2005/6;
- our projection for 2006/7;
- our mean forecast GB losses for 2007/8.

Transmission Losses (TWh)

	2005/6 outturn	2006/7 projection	2007/8 mean forecast
GB TL (TWh)	5.601	5.91	5.82
TLRP (£/MWh)	29	29	43 (assumed)
TL target (TWh)	5.79	5.79	5.82 (assumed)
TLA = {TL – TLT}*TLRP (£m)	–5.5	+3.6	0.0

The mean forecast GB TL for 2007/8 is 0.09TWh (1.5%) lower than our projection for 2006/7. This is a consequence of our assumptions on the disposition of generation, which offset the effect of the increase in Scottish wind generation.

We assume that, under the current net losses scheme, the TL target will be set at 5.82TWh, and so the mean forecast TLA for 2007/8 is zero.

Our scenario-based approach allows us to model the uncertainty in TL volumes, which arises from the forecast variability in:

- Scottish generation
- Transfers across the Anglo-French Link
- Generation in England & Wales.

Across our three scenarios, forecast TL ranges from 5.76 to 5.88 TWh, with a mean of 5.82TWh. This gives forecast TLA ranging from –£2.4m to +£2.7m, with a mean of zero. In the derivation of our probabilistic forecast of IBC, we assume that the losses forecast follows a normal distribution, with a standard deviation of ±0.15TWh (±£6.4m).

9. Balancing Mechanism plus Trades Forecast

Methodology

National Grid's pre-gate trading activities strongly interact with balancing actions in the BM, as forward trades can directly substitute for BM actions. As a result, these two aspects of balancing actions are considered together in an integrated IBMC+Trade model.

The model is a scenario based extrapolation approach, representing the whole year with 36 time periods (3 seasons, 2 day types, and 6 EFA blocks). Historical outturn data for the base period are broken down and processed into an appropriate format in each time period. The model takes into account the scenario assumptions and parameters, and calculates the appropriate amount of pre- and post-gate balancing actions according to the risk profiles and our operating requirements. For example, the amount of pre-gate energy trades is a function of forecast market length (NIV), the forecast price spread between the forward market and the BM, and our risk management policy.

Forecast by Scenario

The table below summarises the forecast costs of IBMC+Trade by scenario, excluding Constraints[xiv].

[xiv] For a full explanation of these terms see section 3, 'Construction of Forecast'.

Costs (£m)	Scenario 1	Scenario 2	Scenario 3	Mean
NIA	55.6	103.4	168.7	106.9
BMC′	85.8	150.6	248.4	157.2
Trade′	6.0	13.8	25.9	14.7
IBMC′	25.2	42.3	74.7	45.4
IBMC′+Trade′	31.2	56.1	100.6	60.0

In general, the cost of IBMC′+Trade′ is a function of the scenario drivers as detailed in section 2.4. For example, Scenario 1 has the lowest forecast cost of IBMC′+Trade′, due to relatively low power prices, favourable bid/offer prices, and long market.

As mentioned above, NIA, BMC′ and Trade′ directly interact with each other and range widely across the three scenarios. For example, NIA varies from +£56m in scenario 1 to +£169m in scenario 3; this is primarily caused by changes in scenario market lengths and forward prices. Therefore, it is generally not useful to consider these terms in isolation.

Splitting the IBMC′+Trade′ costs into an energy component (the total cost of meeting the energy imbalance NIV alone, minus NIA) and a system component gives the following subtotals.

Costs (£m)	Scenario 1	Scenario 2	Scenario 3	Mean
Energy	-106.0	-117.6	-130.8	-117.9
System	137.3	173.6	231.4	177.9
IBMC′+Trade′	31.2	56.1	100.6	60.0

This shows that the energy component is relatively stable across the scenarios (high and low around +/- £12m compared to central), while there is a wide range in system costs, of nearly £100m between high and low. The energy component also anti-correlates with the system component, which indicates that the NIA term continues to help reduce our exposure under BSIS.

The mean forecast cost of IBMC′+Trade′ (i.e. excluding constraints) is £60.0m, with a low case cost of £31.2m and high case cost of £100.6m.

10. Total IBC Forecast and Distribution

Our total forecast of IBC, aggregating all the forecast categories discussed above, is shown in the table below.

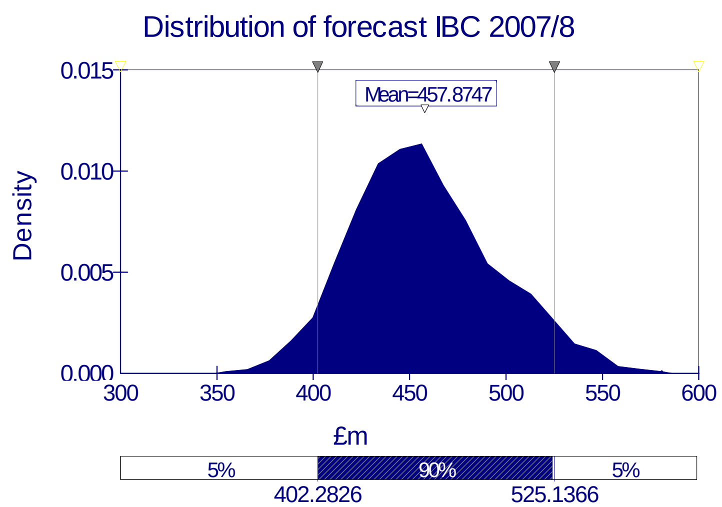
Summary of Forecast Scenario Costs for 2007/08 (£m)

	Scenario 1	Scenario 2	Scenario 3	Mean
	20%	*60%*	*20%*	
IBMC+Trading less Constraints	**31.2**	**56.2**	**100.6**	**60.1**
AS less Constraints	**316.9**	**316.9**	**316.9**	**316.9**
Transmission Losses	**-2.4**	**-0.1**	**2.7**	**0.0**
Constraints	**77.3**	**79.8**	**87.9**	**80.9**
IBC	**423.0**	**452.8**	**508.1**	**457.9**

Note: Scenario probability weighted average

It can be seen that IBC varies from £423m in scenario 1 to £508m in scenario 3. The probability-weighted mean forecast is £457.9m.

There are significant uncertainties surrounding the forecast scenario cost due to the stochastic nature of IBC components. These uncertainties are captured through Monte Carlo simulation of forecast scenario IBC components whose standard deviations are derived from historical volatility. The resulting scenario distributions are combined to give the overall distribution of forecast GB IBC. This is shown below.



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The distribution is slightly skewed, and shows a significant range from a 5th percentile at £402m to a 95th percentile at £525m. The standard deviation of our forecast is £37m.

11. Comparison with Last Year and Current Year

The table below compares the forecast IBC for 2007/8 with historical outturn IBC since BETTA Go-Live. For consistency, the outturns are shown in the same format as the forecast.

Comparison of Forecast with Historical Outturn

	2005/06	2006/07	Variance to 05/06	2007/08	Variance to 06/07
IBMC+Trade less Constraints	125.2	68.1	-57.1	60.1	-8.0
AS less Constraints	228.1	297.8	69.7	316.9	19.1
Transmission Losses	-5.5	3.6	9.1	0.0	-3.6
Constraints	79.7	93.2	13.5	80.9	-12.3
IBC	427.5	462.7	35.2	457.9	-4.8

It can be seen that the larger change in costs is from last year to this year, from £428m to £463m; whereas next year is forecast at £5m lower cost than this year. This effect is even more marked in the breakdown of costs between IBMC+Trade and Ancillary, where the variance from last year to this year sees a swing of some £60m out of BM+Trade costs into Ancillary.

Comparison of 2006/7 with 2005/6

Our projection of £463m for 2006/7 is net £35m above the outturn of £428m for 2005/6. There are many factors driving this increase. For discussion purposes, we have grouped the major changes into the following categories

- Excess costs in 2005/6; (–£25m)
- Volume effects, mainly market externalities which increase the volume of balancing actions we require to maintain system security standards; (+£32m)
- Price effects, directly ascribed to the rise in power prices; (+£4m)
- Price effects, linked to the evolution of competitive pressures and pricing for individual balancing services; (+£44m)
- Efficiency savings, due to new initiatives already in place for this year. (–£20m)

It should be noted that it is not possible to accurately split the forecast cost into the above categories. The allocation of the forecast costs into the above categories is subjective, and should be considered in the context of comparison analysis.

Excess costs in 2005/6 –£25m

Week 51, 13–19/March 2006 saw the coincidence of a spell of cold weather and the outage of Rough gas storage. This increased gas and electricity prices, and drove balancing costs up to unprecedented levels. We estimate that £17m of the balancing costs in that week were definitely attributable to this effect, such that they are a 'one-off' for 2005/6, and unlikely to repeat in future years. (We avoid this issue in our extrapolation forecast of the BM, by omitting this unusual week from the forecast base.)

For this year and next, we have now entered into, or anticipate entering into, an additional volume of contracts compared to the level for 2005/6. We anticipate these contracts will save £8m when compared to the alternative procurement costs seen in 2005/6.

Volume Effects +£32m

We have suffered a high cost of England&Wales constraints this year, under some onerous conditions of both planned and unplanned (fault) transmission outages. This has resulted in costs £9m higher than last year.

We have also suffered high costs of within-Scotland constraints. This is mainly a volume effect, with a heavy transmission outage programme across a number of constraint boundaries interacting with adverse generation patterns. The costs are overall £14m higher than last year.

The costs of re-loading plant in the BM to hold Response and Footroom are strongly linked, because Footroom is the expression of ability to hold High Frequency response. These costs increased by £10m, this year on last year, because of a less benign position of genset FPNs, in terms of providing Response and Footroom without our actions to re-load them in the BM.

After accounting for directly explicable terms, miscellaneous other costs show a decrease of £10m this year on last year. We attribute this to be a volume effect, which offsets some of the volume-based increases discussed above.

Our forecast of the net cost of Transmission Losses, namely the TLA term, shows an increase of £9m. This can be entirely explained by the increase in Scottish generation, as much an increase in conventional generation as an increase in wind generation.

Price Effects, due to Power prices +£4m

Average base load power price has moved up from £41/MWh for 2005/6 (average day-ahead price), to £44/MWh for 2006/7 (half actual and half forward price at the time of writing). According to the observed relationship of BM prices paid for Margin / Reserve the BM to power prices, as illustrated in the discussion above of BM to power price ratios, this power price increase will cause an increase of £9m in the costs of procuring Margin / Reserve in the BM this year.

The net cost of balancing the energy –i.e. the net length– of the system is represented within IBC by the difference between the direct cost to us of purchasing Bids or Offers or Trades to meet the system length, and the NIA term which compensates BSIS for this effect, by setting a target price for us to balance the system. As power prices rises, this net cost of energy balancing grows more negative; for example, BSIS sees greater income from the acceptance of Bids to meet the system length. Overall, this effect, as represented within our IBMC+Trade extrapolation model, shows a reduction of £5m from last year to this.

Price Effects, due to evolution of Balancing Services +£44m

CAP047 permits generators to submit commercial prices for the holding of Ancillary response. As shown above, prices doubled on the implementation of CAP047, and have continued to rise since. Because CAP047 is in place for all 12 months of 2006/7, rather than for just 5 months of 2005/6, and because of the continuing price rises, costs of Mandatory Ancillary response are £24m higher this year than last.

This rise in the costs of Mandatory Response have been factored into submissions under firm frequency response tenders. We are paying £9m more this year than last, across a comparable volume of purchase.

We have experienced an increase of £11m across the prices paid for Standing Reserve availability and utilisation, and certain Constraint services, year-on-year.

Efficiency Savings –£20m

Our exposure to the following costs is subject to an agreed level within BSIS 2005/6. Costs outside this level may be subject to an IAE. For the BSIS 2006/7 a central forecast for these costs has been produced and, as discussed above, assumes no specific IAE mechanism.

After allowing for the effects of extra contracts (second bullet of 'Excess Costs' above), and of power prices, our projected costs of Margin plus Fast Reserve are £5m lower this year than last. We believe this represents an efficiency saving, of continually improving setting of requirements and dispatch of services, which has resulted in a volume reduction in the procurement of these services this year.

New contracts for Reserve and Constraint services are delivering a further £15m reduction in costs year-on-year.

Comparison of 2007/8 with 2006/7

Our forecast of £458m for 2007/8 is £5m below our projection of £463m for 2006/7. There are fewer factors driving this change, than the corresponding factors relating this year to last, and for discussion purposes, we have grouped the major changes into the same categories as above:

- Volume effects, a number of which partially reverse the corresponding changes seen 2006/7 on 2005/6; (–£18m)
- Price effects. (+£13m)

It should be noted that it is not possible to accurately split the forecast cost into the above categories. The allocation of the forecast costs into the above categories is subjective and should be considered in the context of comparison analysis.

Volume Effects (–£18m)

This year's high cost of England & Wales constraints, totalling £29m, we regard as unnaturally high. £7m is linked to one unplanned transmission system fault event, and our forecast of £22m for next year represents the same level of underlying costs year-on-year, but excludes this £7m.

Our initial studies of the transmission outage programme within-Scotland show that it is less onerous than this year's outage programme across constraint boundaries, and accordingly our forecast is that within-Scotland constraints will cost £7m lower than this year due to this effect.

Our forecast of the net cost of Transmission Losses, namely the TLA term, shows a decrease of £4m. This is because, despite the increase in Scottish wind generation, we forecast a greater decrease in Scottish conventional generation, and also beneficial changes to the disposition of generation in England & Wales.

Price Effects +£13m

The net cost of balancing the net length of the market is represented within IBC by the difference between the direct cost to us of purchasing Bids or Offers or Trades to meet the system length, and the NIA term which compensates BSIS for this effect, by setting a target price for us to balance the system. As power prices rise, this net cost of energy balancing grows more negative; for example, BSIS sees greater income from the acceptance of Bids to meet the system length at an average Bid price of 25 £/MWh (forecast), rather that at an average of nearer 20 £/MWh (this year). Overall, this effect, as represented within our IBMC+Trade extrapolation model, shows a reduction of £2m from this year to next.

Again, as in the above variance for 2006/7 on 2005/6, the net cost of energy balancing increases, as power prices fall. Overall, this effect, as represented within our IBMC+Trade extrapolation model, shows a +£4m increase from this year to next.

We forecast continuing, albeit gentle, rises in CAP047 response prices, and thus a cost rise of +£7m for Ancillary response holding.

In line with experiences previous year to last year, and last year to this year, we forecast a more moderate increase of +£6m across the costs for Standing Reserve availability and utilisation, and certain Constraint services, year-on-year.

After accounting for directly explicable terms, miscellaneous other costs, including those of BM Response plus Footroom, show a decrease of £2m next year on this year. We attribute this to be a price effect, which offsets some of the price-based increases discussed above.

Comparison of July and October Forecasts for 2007/8

In July, we made an early forecast of £483m for 2007/8, to aid initial discussion. This document (the 'October forecast') describes our current forecast of £458m. At a high level, the differences between the two can be summarised:

- The reduction in forecast power price, from £51/MWh to £43/MWh in line with forward prices, reduces the forecast costs across the BM+Trades, and also Reactive; (−£37m)
- We have been able to include some outturn Ancillary volumes for summer 2006 in the October forecast; (−£5m)
- The forecast of Constraint cost has risen, but by less than the corresponding rise seen in this year's Constraint costs; (+£9m)
- We have more fully understood the level of this year's Response price rises, and increased the forecast, albeit still moderately, of next year's Response prices; (+£8m)

Further comparison of the two forecasts is problematic as the July forecast necessarily used approximate methods, whereas this October forecast applies our full forecasting methods, and uses up-to-date data.

12. Conclusion

The systematic increase in balancing costs seen since 2004/5 has been driven by three major factors; increases in Power prices; Scottish constraint costs and the introduction of CAP047. However it is National Grid's view that these costs will now start to stabilise, and thus, in terms of our overall forecast of Incentivised Balancing Costs, we forecast a slight fall in IBC compared with our current projected outturn for 2006/7.

Comparing last year's outturn of £428m with next year's forecast of £458m can be considered by summating the year-on-year variances discussed above. It can be seen that all the forecast cost increase (+£35m) is happening this year, 2006/7, and next year, 2007/8, sees a slight forecast decrease (–£5m).

In both years, the driver of increasing prices across balancing services, most significantly that of CAP047 Frequency Response prices, albeit with a much smaller rise in 2007/8, is offset by a number of volume variances. National Grid's efforts to contain the volume of balancing services are being offset by the prices submitted for us to meet our requirements.

However significant uncertainty remains with regard to forecasting next year's costs. In our opinion the area of greatest uncertainty within the forecast is the evolution of 'winter' balancing costs following the high levels seen last winter. We will look closely at how these costs evolve through November – January and assess what impact these outturns might have on our current forecast.

In addition, we also face uncertainty regarding the evolution in power prices and, separately, trends in several key Ancillary Service costs. These are:

- Continued evolution of Frequency Response Holding prices, in particular following the introduction of CAP107 changes on 28th December 2006.
- Changes in commercial frameworks resulting from ameliorations to two balancing services. BM Start Up was introduced to replace the old 'Warming' service on 2nd November 2006. STORT will replace the Standing Reserve and Supplemental Standing Reserve tenders from 1st April 2007. We shall receive the first tenders for this new service in January.

As we move forward into the winter and gain additional certainty as to the likely levels of winter costs and the effects of changes to the procurement regime for Ancillary Services, we will look to provide updates to Ofgem as more data becomes available through the winter and in particular in January 2007, once the initial impact of CAP107 and STORT becomes clearer. Primarily, this information will change our projection of costs for this year, but it will also better inform views of costs for next year.

STOP PRESS

This appendix is drafted, exactly as we presented our forecast to Ofgem in mid October. It is now end November, and inevitably, the story of Incentivised Balancing Costs (IBC) has moved on.

Our current projection for this year 2006/7 has increased to £480.9m. The increase of £18.2m from the £462.7m presented above is mainly due to outturn costs above forecast in September, October and November. These are mainly further Constraint costs and the consequences of the severe level of nuclear outages at present.

This latest projection, at £480.9m, serves to illustrate the ongoing uncertainty of winter costs, as discussed elsewhere in this appendix. We will continue to review costs this winter, assessing their impact on our forecast view for 2007/08 and providing updates to Ofgem as appropriate.

Appendix 7 - Frequency Response Analysis

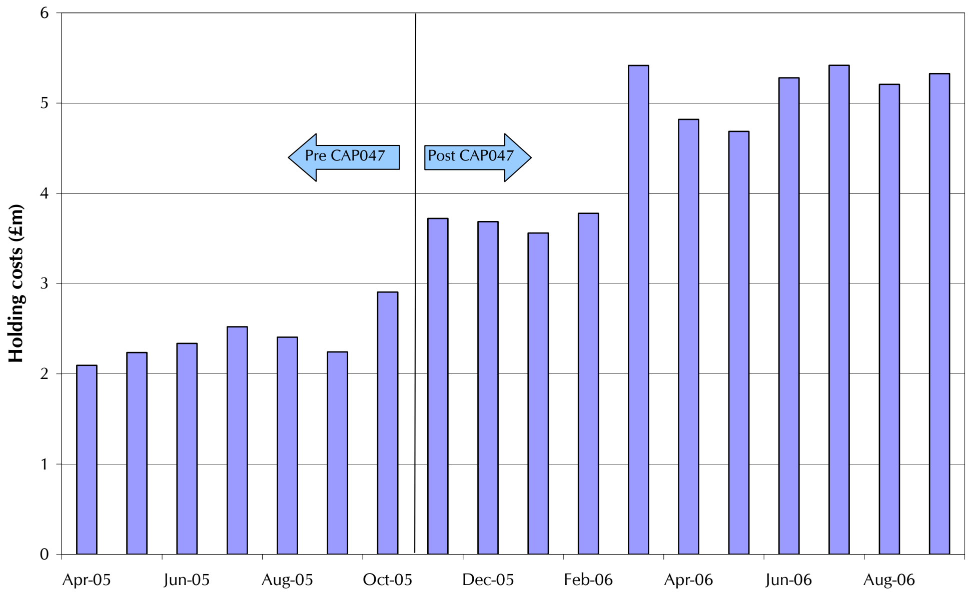
1.1. This Appendix describes the analysis of frequency response costs that we and NGET have undertaken in order to gain an understanding of what has driven the increase in these costs since the implementation of CAP 047 at the beginning of November 2005. Ofgem anticipated that there would be some increase in frequency response costs following the introduction of CAP047 because we were of the view that the prices under pre-CAP047 arrangements might not appropriately reflect the costs faced by market participants when providing frequency response. However, a number of market participants have expressed concerns regarding the size of the increase and the fact that costs are continuing to rise.

1.2. In this appendix, we provide information on the development of frequency response costs since the implementation of CAP047 and an initial assessment of what factors may have contributed to the rise in costs.

Development of frequency response holding costs

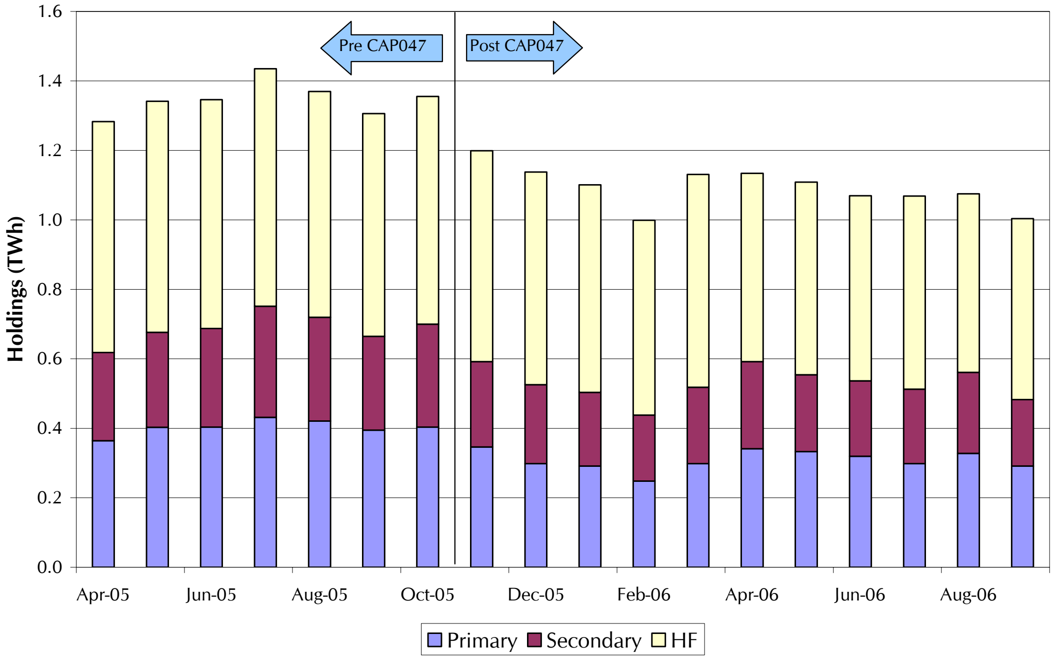
1.3. Figure 1 below shows how monthly holding costs for frequency response rose sharply upon the introduction of CAP047, stabilised for around four months, and then rose again in March 2006 and have remained at this higher level since then.

Figure 1: Monthly holding costs



1.4. This increase in costs has occurred despite the fact that NGET has reduced the level of mandatory response that it holds, as shown in Figure 2. (Indeed, NGET has suggested that one reason why mandatory frequency response costs may have stabilised is that it is now relying more upon commercial frequency response contracts.) In other words, the increase in holding costs appears to be due to increases in the offer prices that market participants have submitted for the provision of mandatory response.

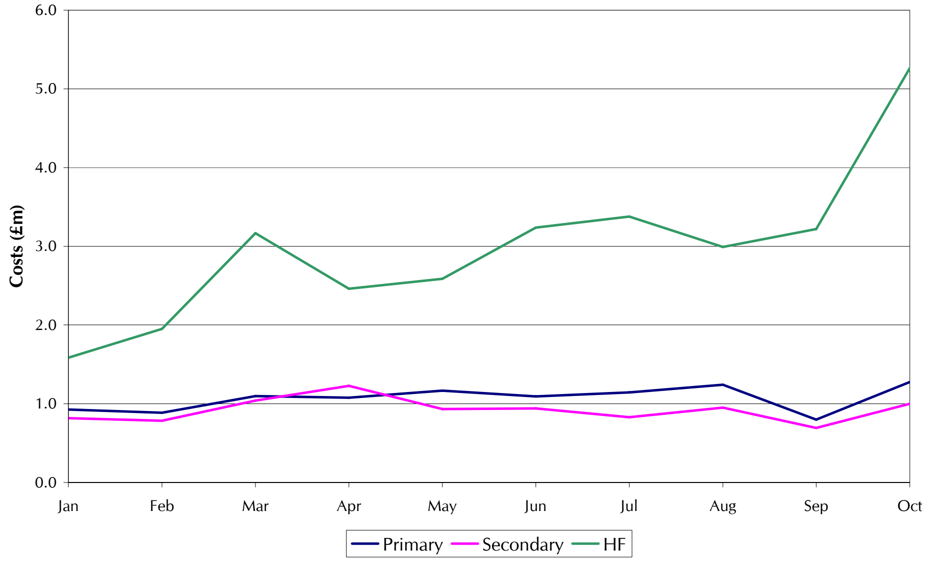
Figure 2: Monthly mandatory response holdings



1.5. Of the three types of frequency response: primary, secondary and high frequency (HF), it is the costs of high frequency response[1] that have increased the most after the initial rise in November 2005, as can be seen from Figure 3. Consequently, in the analysis that follows, we have concentrated primarily upon analysing the development of HF costs.

[1] Generators providing high frequency response reduce the output of their power stations when the frequency of the system rises above its target level of 50 Hz.

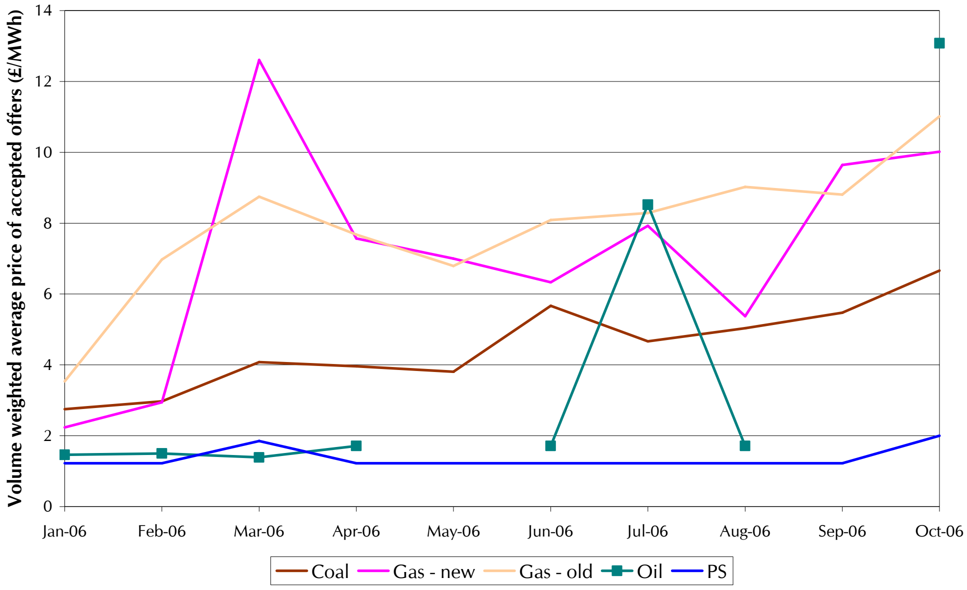
Figure 3: Breakdown of frequency costs by service



1.6. We have examined how the HF offer prices have developed over time for power stations fired by different types of fuels. Specifically, we have looked at the development over time of the volume-weighted averages of prices of accepted offers for new (post-1996) and old gas-fired stations, coal-fired stations, oil-fired stations and pumped storage (PS) stations. The results of our analysis are shown in Figure 4.

1.7. This demonstrates that all types of power stations, with the possible exception of pumped storage units, have been able to increase their offer prices and still have their offers accepted. The most significant increases have been in gas-fired plants (both old and new) and oil-fired plants, although offers from oil-fired plants have only been intermittently accepted. Those from coal-fired plants have also doubled.

Figure 4: Accepted response prices by fuel type



1.8. As might be expected from the data shown in Figure 4 it is also the case that the volume-weighted averages of the accepted offer prices of most generation companies have increased, although the increases have generally been less marked for those companies that only own a single power station. This is illustrated in Figures 5 and 6, where we have used information available on the NGET website to illustrate the profiles of offer prices submitted by a selection of generators.

Figure 5: Accepted HF response prices by different generating companies

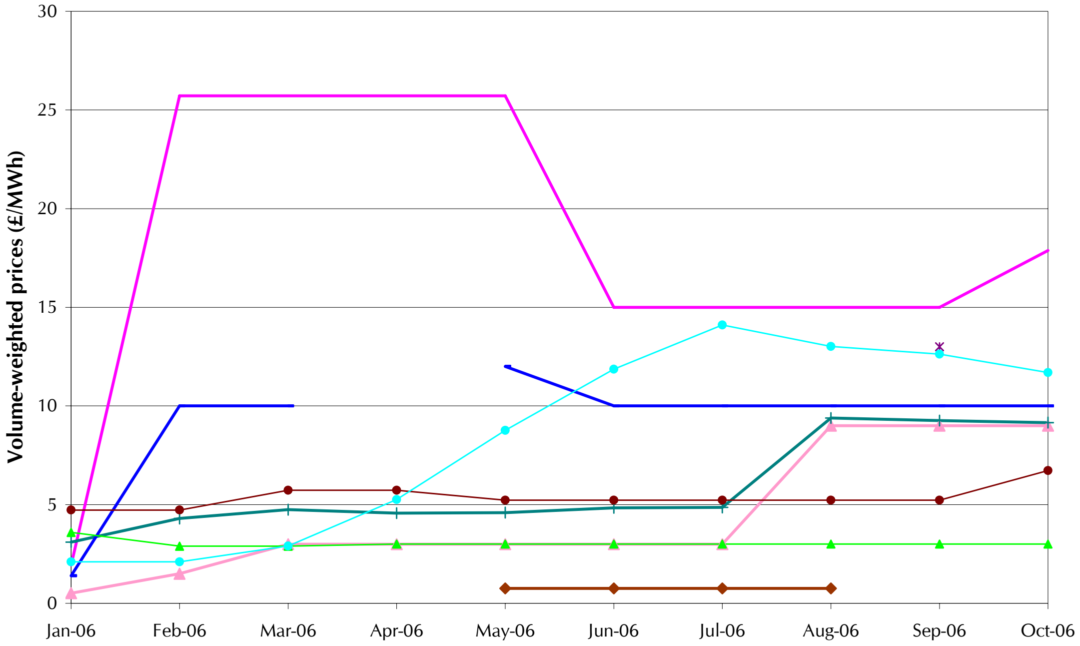
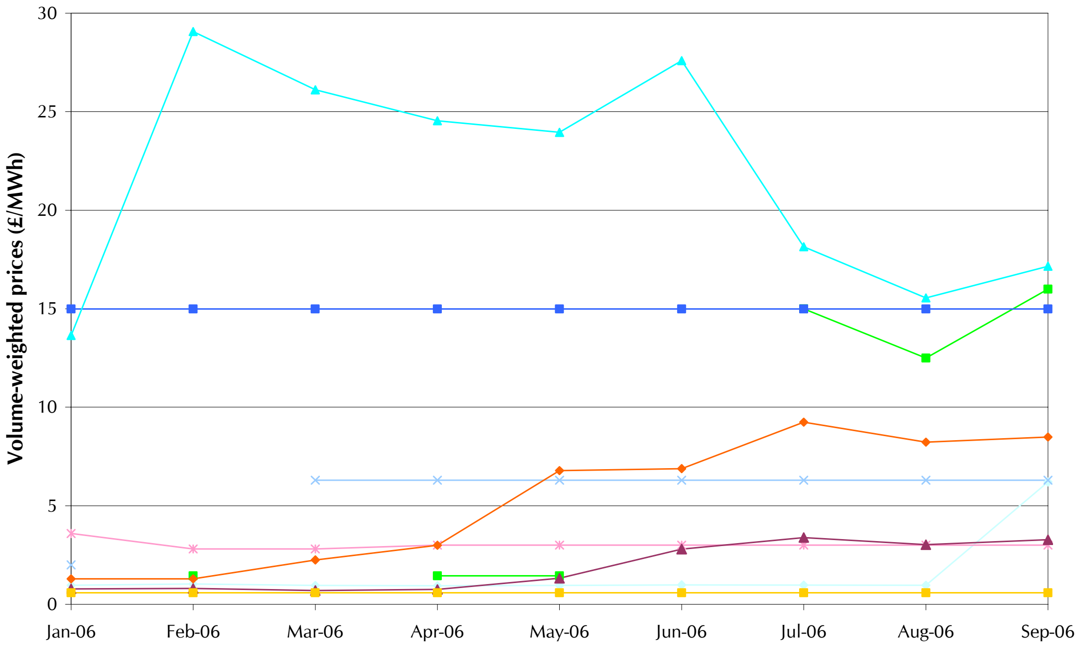


Figure 6: Accepted HF response prices by different generating companies



Potential drivers of costs

1.9. We have shown, in the preceding discussion, that frequency response costs have increased very significantly since the introduction of CAP047. Accordingly, we have undertaken further analysis to determine what drivers might be causing these cost increases. We have examined two possible reasons for this increase:

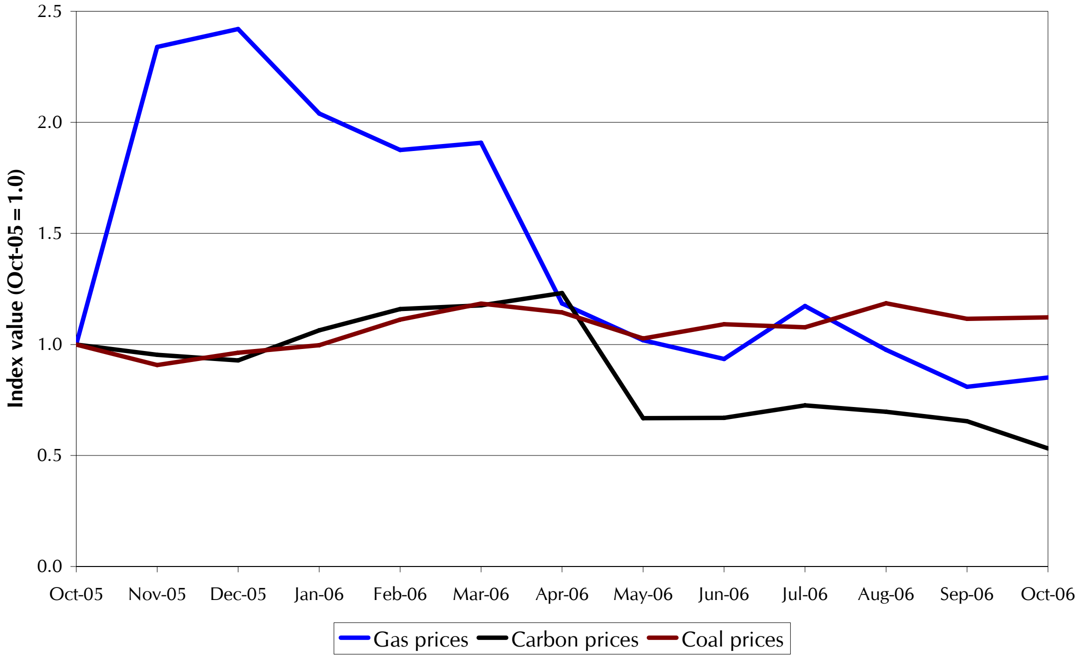
- the possibility that pre-CAP047 payments did not fully cover the actual costs of providing frequency response, and
- the possibility that pre-CAP047 payments did not cover the opportunity costs of providing frequency response.

Costs of providing frequency response

1.10. As discussed previously, it has been suggested that the compensation that generators received pre-CAP047 for operating in a frequency responsive mode did not adequately cover the increase in costs that they faced when operating in this mode. If this were the case, we would have expected that the removal of this constraint would have primarily resulted in a one-off increase in holding prices with, perhaps, further small increases in the following couple of months. In other words, this explanation does not account for the increase in holding prices seen after January 2006.

1.11. If the fuel-related costs of providing frequency response had increased following the introduction of CAP047, then this would provide an explanation for the increases in holding price offers. To investigate this possibility, we have examined how coal, gas and carbon prices (in sterling terms) have developed since Oct-05. For ease of comparison with the holding prices shown in Figure 4, we have shown these prices as indices reflecting how their values have moved since Oct-05. Figure 7 shows that, with the possible exception of an initial increase in the offer prices for gas-fired plants in Oct-05, there is no evidence to suggest that fuel/carbon price movements have contributed to the increase in holding prices.

Figure 7: Coal, gas and carbon price indices

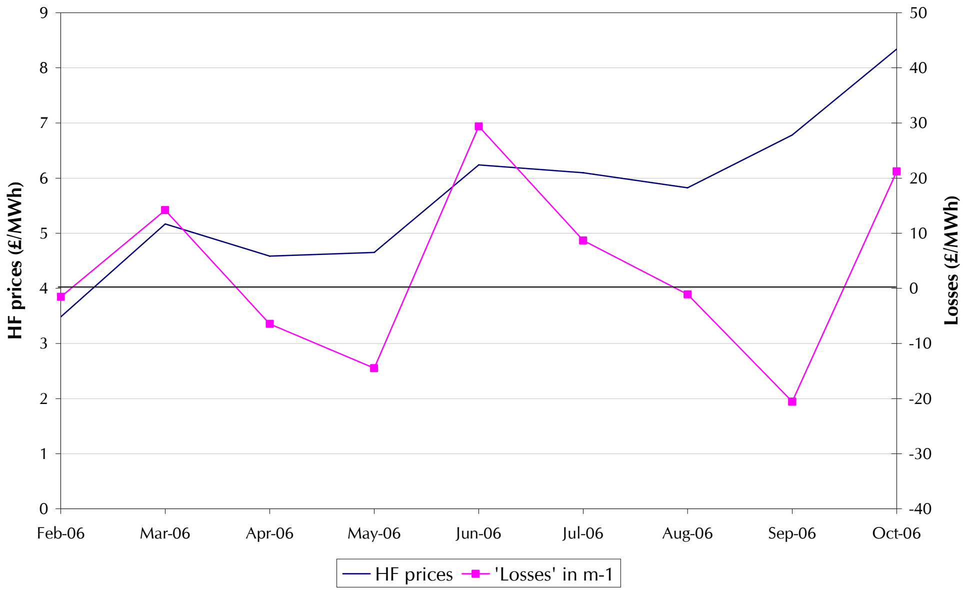


Opportunity cost of providing frequency response

1.12. When providing high frequency response, generators are reducing their output and hence potentially foregoing revenues that they would otherwise earn either in the Balancing Mechanism or from energy sales. Under the current rules, the energy payment that they receive for providing frequency response during a month is equal to the average of the system buy and system sell prices from the previous month. Accordingly, if balancing/energy prices are higher in the current month than they were in the previous month, the generators may consider that they face an opportunity cost when providing frequency response. This might then feed through to the holding price offers that they submit.

1.13. We have therefore analysed whether an opportunity cost argument could explain the development of high frequency holding costs by comparing how high frequency holding price offers have developed against a measure of the opportunity cost "losses" that generators may have faced in the preceding month (m-1). We have estimated the losses for a month as the difference between the energy reference price paid for providing response with the average of the system buy price for that month. In other words, we assume that if the generators had not been providing high frequency response, they would have been selling that power in the Balancing Mechanism. We have used the system buy price as a proxy for the price that generators would have been paid for such sales, recognising that this can approach can only be indicative of the opportunity costs faced by generators rather than an accurate estimate. On this basis, Figure 8 shows, there is some evidence that opportunity costs may have accounted for some of the holding price increases in the early months of 2006. In both Mar-06 and Jun-06, the increase in HF holding prices coincided with a peak in the potential losses that generators might have made in the preceding month and HF costs went down when the 'losses' went down (or were negative). However, the sustained rise in HF costs in Sep-06 cannot be traced back to this measure of opportunity costs.

Figure 8: Opportunity cost analysis



Conclusion

1.14. Frequency response costs have more than doubled since the introduction of CAP047. Our analysis indicates that these increased costs have primarily occurred due to widespread rises in the holding price offers made by generators. The above analysis has examined some of the underlying explanations for these rises. **We invite views from interested parties on this analysis and on the potential causes of these price increases.**

Appendix 8 - Indexation Option Analysis

Introduction

1.1. This Appendix describes the analysis that we have undertaken in order to develop an indexation option for the incentive scheme on SO external costs. The analysis includes establishing the extent to which individual IBC components are correlated with wholesale prices, and the appropriate deadband outside of which wholesale prices would be required to move for the IBC target to be amended.

1.2. This analysis is based on initial data, some of which is limited in its volume. If respondents consider that this type of indexation is appropriate we will look to undertake further analysis ahead of the Final Proposals to ensure the correlations used are appropriate.

1.3. We start by describing the methodology that we have used in undertaking the correlation analysis and then present our results for overall IBC, its major components and the individual balancing services contract costs. Based on this analysis, we derive adjustment factors under two different approaches, determine the proportion of overall IBC that would be linked to wholesale prices under these approaches, and illustrate what their impact on the incentive target could be. Finally, we consider the level of price volatility that has been seen historically seen. We then use this analysis to determine the deadband of wholesale prices within which there would be no adjustment to the target,

Correlation analysis

1.4. We have looked at the correlation between overall IBC and wholesale prices, between each of the major components of IBC (CSOBM, BSCC, NIA and TLA) and wholesale prices and between individual components of BSCC and wholesale prices. In each case, we have examined the correlations with baseload and peak prices.[1]

[1] For simplicity, we use the terms correlation and coefficient interchangeably when discussing the output results. We have completed the analysis based on linear regression modelling in which the independent variable X (i.e. wholesale prices) is regressed against the dependent variable Y, (i.e. IBC or one of its components) for the same period. The resulting equation yields an intercept term, a coefficient value that represents the change in Y for a unit change in X and an error term.

Methodology

1.5. Since we are interested in the impact that changes in wholesale prices may have on IBCs over the course of a year, we have measured the correlation between the rolling annual sum of IBC (or its components) and the rolling annual average wholesale price. In other words, the data that we use for, say, 1 April 2005, are the sum of the daily IBCs from 1 April 2004 to 31 March 2005 and the average of wholesale prices over the same period. However, or the individual components of BSCC we have only used monthly data, rather than daily data. If, we are to develop this option further as a final proposal we will undertake more detailed analysis on available daily data.

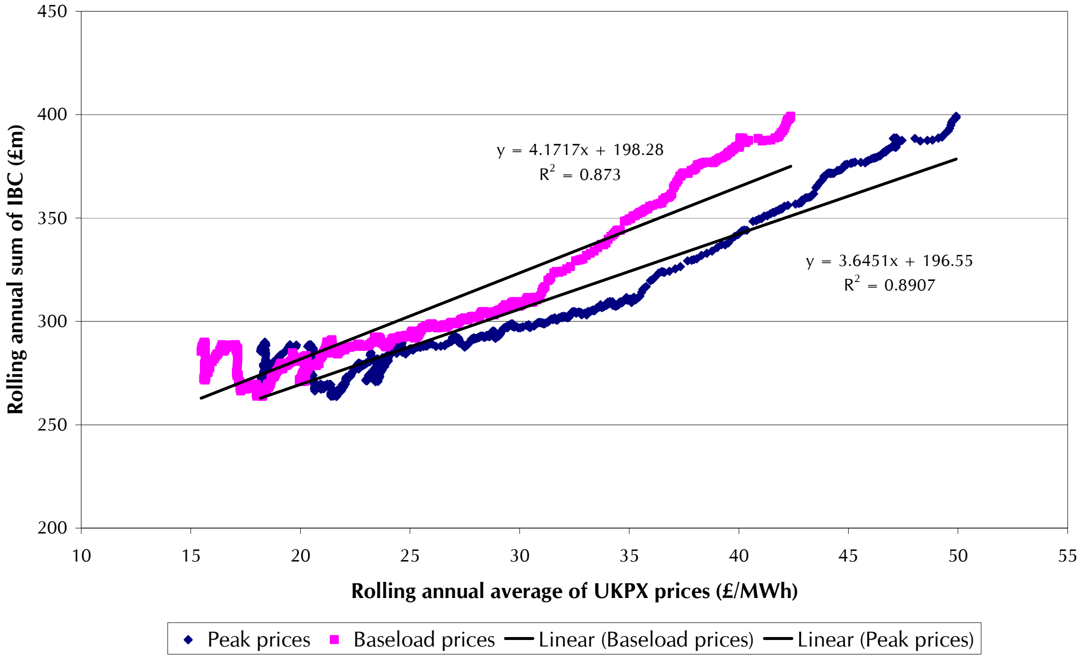
1.6. For wholesale prices, we used UKPX hourly reference prices. We defined peak prices as the average of prices from 07:00-07:30 to 18:30-19:00 on all days and baseload prices as prices between 00:00-00:30 and 23:30-00:00 on all days. Note that the baseload price definition is not the same as that used for UK daily prices, which starts at 23:00, but was chosen to be consistent with the daily IBC information that we have.

1.7. In our analysis, we have excluded data from the first year of NETA i.e. 2001/02, since this is likely to have been a period when both NGET and market participants were learning how to operate under the new trading arrangements.

Overall IBC analysis

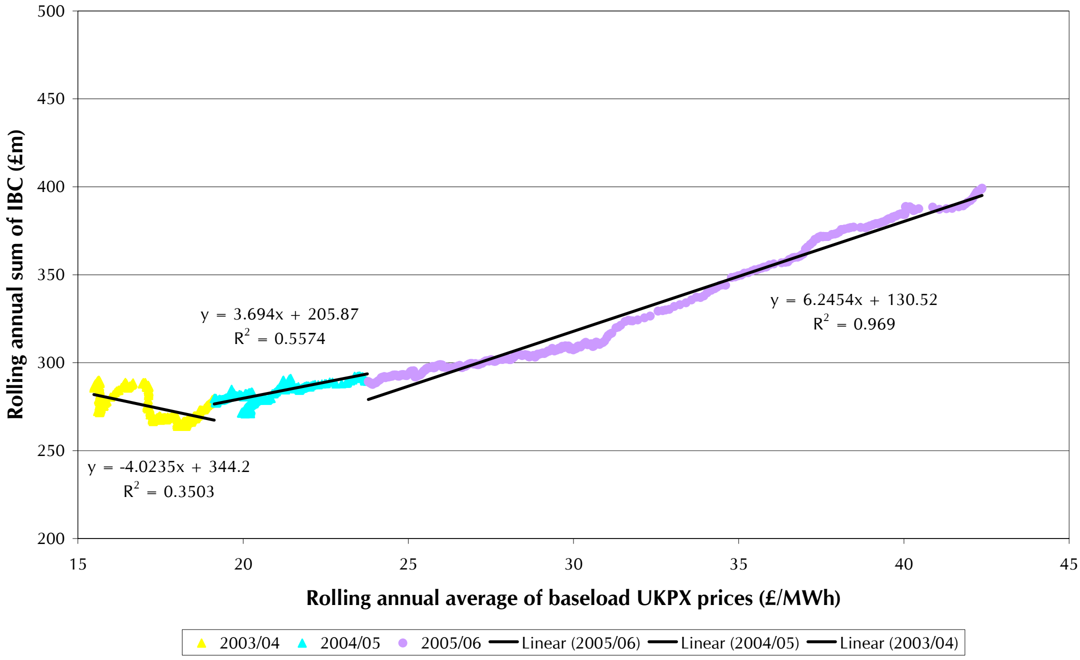
1.8. Figure 1 below shows the results of our analysis of the correlation between overall IBC and UKPX prices for both peak and baseload prices. Whilst it demonstrates that there has been a correlation, it also indicates that the correlation has not been perfect. This result also reflects our view outlined in the document that some elements of the scheme are more closely related to wholesale prices than other elements.

Figure 1: Correlation of overall IBC against UKPX prices – 2002 to 2005



1.9. In particular, the correlation between IBC and prices appears to have become stronger as IBC and prices have increased. The increasing correlation can be seen from Figure 2, which measures the correlations on a year by year basis. There have, of course, been changes in the balancing and settlement arrangements over time that may have affected the correlation between prices and IBC.

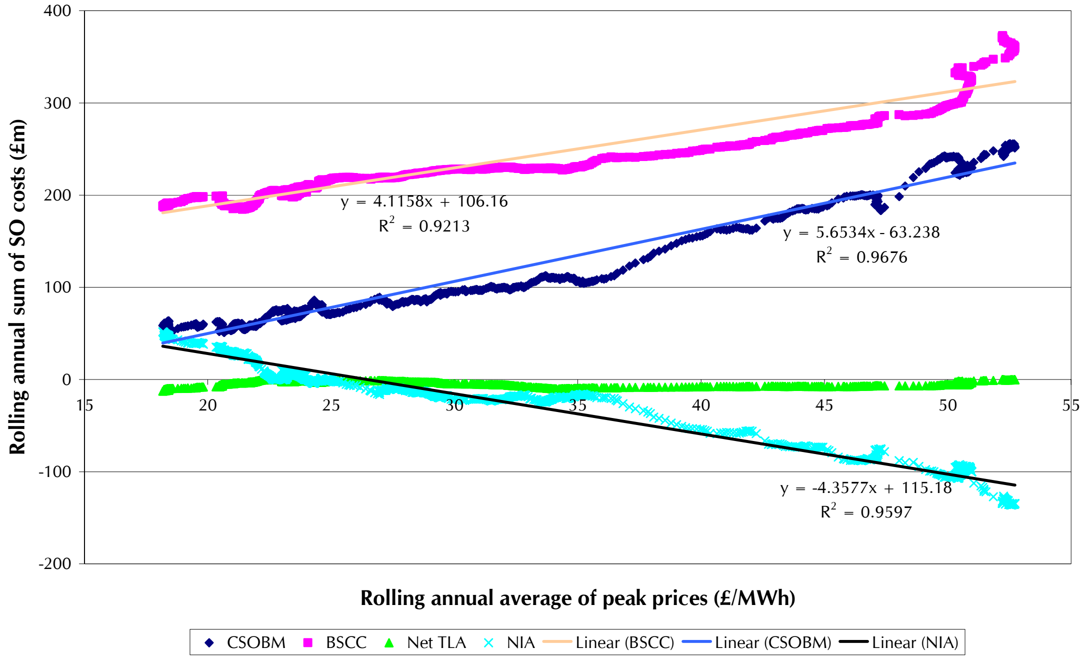
Figure 2: Correlation of overall IBC against UKPX baseload prices – by year



IBC component analysis

1.10. In addition to analysing the correlation between overall IBC and wholesale prices, we have also analysed the correlation between each of the major components of IBC and wholesale prices. Figure 3 shows the results of this analysis.

Figure 3: Correlation between IBC components and UKPX baseload prices – 2003 onwards



1.11. Our analysis shows that there has generally been a strong correlation between the major components of IBC and baseload wholesale prices, with the exception of TLA. We would not expect there to be a correlation between TLA and wholesale prices since this component of IBC has in the past depended on a fixed reference price.

1.12. Whilst there is a strong correlation between CSOBM and wholesale prices, we recognise that there are some actions that NGET takes in the BM for which the costs should be more correlated to wholesale prices than others. In particular, energy balancing actions within the BM are likely to be strongly correlated with wholesale prices, whilst this should not be the case for system balancing actions.[2] Moreover, the payments for certain system balancing services are currently defined in such a way that they may be expected to vary with wholesale prices. For example, reactive power energy payments are explicitly linked to imbalance prices. Consequently, in our indexation analysis we have used the term "energy" trades to refer to all actions taken by NGET that can be expected to vary with wholesale prices. This is a broader definition than the standard definition of energy balancing actions.

[2] Note that this arises because while NGET forecasts the costs of constraints separately, for reporting purposes some of these costs are included in CSOBM. It is not possible accurately to separate out these constraint costs for the purpose of determining the historical relationship between energy balancing actions within the Balancing Mechanism and wholesale prices.

1.13. However, as a result of the current difficulty in separating NGET's actions into these two separate components we consider that it is appropriate to consider indexing on the whole of CSOBM. We note that the separation of system and energy actions is one area that will be looked at as part of the cash out review which is to start in 2007, so the effect of their separation on possible indexation options can be considered further as part of the review of SO incentives over the longer term.

BSCC component analysis

1.14. We further investigated the correlation between individual balancing cost services (i.e., the components of BSCC and wholesale prices). As discussed previously, the only difference between the analysis above and the approach we have taken for BSCC components is that we have used monthly data for the BSCC components rather than daily data. However, as discussed, if we develop this option further as a final proposal, we will work with NGET to undertake more detailed analysis.

1.15. Our analysis shows that, as expected, some individual components of BSCC were more closely correlated to wholesale prices than others, as shown in Table 1 below.

Table 1: BSCC Components & Wholesale Prices Correlation Statistics (sorted in descending order of R-squared)

BSCC component	Coefficient	R-squared
Reactive Power	0.8	0.98
Black Start	0.2	0.88
Warming Contracts	-0.7	0.87
OTC Energy (Trades)	1.1	0.83
Fast Reserve	0.6	0.71
Firm Part Loaded Response	0.5	0.65
System to System Service	0.3	0.58
Intertrip	0	0.46
Transmission Related Agreements	0.6	0.46
Other Reserve	0	0.34
Power Exchange Trades	0.4	0.31
Standing Reserve & Supplemental Standing Reserve	0.6	0.32
Mandatory Frequency Response	0.3	0.21
Demand-Side response	0.2	0.18
Fast Start	0	0.17
Demand Turndown	0	0.11
Ancillary Services (Other)	0	0.1
Pre- Gate Balancing Transaction	-0.1	0.01

Components to be indexed

1.16. We have developed two alternative approaches for determining which components to include in indexation:

- a **statistical** approach: Using the correlation analysis, we have selected those components with an r-squared value greater than 0.7. This would result in indexing the following components: reactive power, black start, trades, fast reserve, and warming. In addition, we would index CSOBM, and NIA, which, as shown in the section above, have r-squared values of 0.98 and 0.95 respectively.

- a **categorisation** approach: As an alternative, we have selected those items that are most likely to be "energy" related rather than "system" related. This would result in indexing CSOBM and NIA, as above, as well as reactive power, trades and all elements of reserve (fast, standing, supplemental standing, and other reserve) from the BSCC.

1.17. We developed the second approach in recognition of the limitations of the statistical approach given the fact that it appears likely that the correlations for the various balancing services may have varied over time. (This is evidenced by the change in the correlation between overall IBC and wholesale prices over time.) Consequently, depending on the period and threshold chosen for analysis, the elements that would be included in the statistical analysis change. However, it seems unlikely that the underlying relationship between a particular service and wholesale prices should have changed. The categorisation approach avoids this problem.

1.18. Taking the relevant coefficients (or sum of coefficients) from Table 1 above, the relevant adjustment factors based on each of these approaches are shown in Table 2 below.

Table 2: Adjustment factors - statistical approach

Component	Change in target (£ million for every £/MWh change in wholesale price)	
	Statistical approach	Categorisation approach
CSOBM	6.6	6.6
NIA	-5.1	-5.1
Trades	1.1	1.1
Reactive Power	0.9	0.9
Fast reserve	0.5	n/a
Black start	0.2	n/a
Warming	-0.7	n/a
All reserve	n/a	1.2
Total	3.5	4.7

Targets for indexed components

1.19. Using these two approaches, we can then determine the amount of total IBC that would be subject to indexation. To do this, we have used the expected outturn for each of the relevant components included in NGET's October forecast and pro-rated each to be in line with our expected outturn of £430.

1.20. Using the statistical approach, of the expected £430 million of IBC costs, £275 million would be indexed to wholesale prices whereas £317 million would be indexed to wholesale prices under the categorisation approach.

1.21. For the avoidance of doubt, whilst we have broken down the overall target into the individual components to establish the link to any change in wholesale prices, we are still proposing a single IBC target. Therefore, we believe that it is appropriate to determine an adjustment factor that can be applied to overall IBC.

1.22. For example, using the coefficient factors from Table 2, the adjustment factors to be applied to our proposed target of £430 would be as follows:

- For the **statistical approach**, we would apply an **£3.5 million adjustment to the IBC target** for each £1/MWh change in wholesale baseload prices (outside the deadband, discussed further below). This gives the same result that would be obtained if you were to set a CSOBM target, then adjust it by £6.6 million, or set a NIA target and reduce it by £ 5 million, etc, in response to the same £1/MWh change in prices.
- For the **categorisation approach**, we would apply a **£4.7 million adjustment to the IBC target** for each £1/MWh change in wholesale baseload prices (beyond the deadband, discussed further below).

Establishing the deadband

1.23. As discussed in the main document, we believe the appropriate form of indexation is to have a deadband within which NGET must still manage its own price risk. Only movements outside this deadband would result in adjustments to the IBC target.

1.24. To determine the size of the deadband, we examined the degree of recent volatility in the wholesale electricity markets, as shown in Table 3below, by tracking the difference between the forward price for each year in the September prior to the start of each incentive scheme ("starting point") and the outturn price ("final value"). For each of the last four years, with the exception of 2005/06, the degree of variation was within +/-10%. In 2005/06, variability increased to 20%.

Table 3: Variability in wholesale electricity prices[3]

	Max	Min	Std Deviation	Average	Starting Point	Final Value	% Change
2003/04	23.0	14.4	2.7	18.2	14.8	19.1	9%
2004/05	32.4	21.0	2.2	24.0	21.8	23.8	9%
2005/06	52.6	28.7	5.8	39.0	35.3	42.4	20%
2006/07	58.7	42.9	4.1	50.6	45.7	43.3	-5%

1.25. **Therefore, we consider that a change in prices of more than 10% may be indicative of a "structural break", and may be the appropriate level for a deadband. We believe NGET should be incentivised to manage the risks of price changes less than 10%.** Therefore, if prices increase or decrease by more than 10%, the target IBC would be adjusted for every additional £1/MWh change in outturn wholesale prices above the 10%.

Indexation option

1.26. The following section summarises our indexation options including the deadband, and the adjustment factor, caps and sharing factors.

1.27. We have developed two variations of indexation options:

- **Based on the *statistical approach*, the indexation option would include a deadband of +/- 10% around an agreed wholesale price (annual baseload), such that for every £1/MWh change in outturn wholesale prices above the 10%, the IBC target would be altered by £3.5 million, in the same direction.**

- **Based on the *categorisation approach*, the indexation option would include a deadband of +/- 10% around an agreed wholesale price (annual baseload), such that for every £1/MWh change in outturn wholesale prices above the 10%, the IBC target would be altered by £4.7 million, in the same direction.**

1.28. We view these indexation options as low risk/low reward options. Consequently, we consider that the same caps, floors and sharing factors as for Option 1 are appropriate (i.e., upside sharing factor of 7.5%, and a downside sharing factor of 10% with both cap and floor at £5 million). However, we are proposing a slightly lower target than under Option 1 as these indexation options remove some of the risk to NGET of wholesale prices increasing.

1.29. As examples of each approach, assume that our agreed view of expected wholesale prices for 2007/08 was £40/MWh (i.e. this was the basis on which the IBC

[3] 2006/07 prices based on six months of data.

target is agreed), then the deadband would be +/- £4/MWh. If the actual annual price turned out to be £34/MWh, which is £2/MWh outside the deadband, then:

- based on the *statistical* approach, the IBC target would be reduced by £7.0 million.
- based on the *categorisation* approach, the IBC target would be reduced by £9.4 million.

Conclusions

1.30. The analysis presented in this appendix has shown that there are correlations between certain elements of IBC and wholesale prices. On the basis of this analysis we have developed two different approaches to determining an appropriate adjustment factor to apply to the target for NGET's external SO incentive scheme. We have also used an analysis of historic price volatility to derive an appropriate width for the deadband for prices within which there would be no indexation of the target. **We invite views from interested parties on all aspects of the analysis we have presented and, in particular, the values for the adjustment factor and the deadband.**

Appendix 9 - Licence Drafting

1.1. This appendix outlines key elements of changes to licence drafting that would be necessary to implement the changes proposed in Chapters 2 and 3 of this consultation document. These changes are outlined in turn for:

- electricity external incentives, and
- gas external incentives.

1.2. In each instance we only include the drafting relating to the implementation of the numerical proposals that we have put forward for the incentives for 2007/08. In other words the licence drafting that follows does not represent the full set of changes that would be required to give effect to our proposals.[1]

Electricity - external

1.3. We consider that licence changes will be necessary to implement our proposals relating to:

- changes in the IBC target, and
- treatment of transmission losses.

Changes in the IBC target

1.4. In Chapter 2, we outlined a number of alternative options for the IBC target. Licence drafting is presented below for each of these options.

Option 1

1.5. The numerical amendments to Schedule A (Supplementary Provisions of the Charge Restriction Conditions), Part B (Terms used in the balancing services activity revenue restriction) Paragraph B1 of NGET's Transmission Licence are shown below.

1.6. For existing paragraph B1, substitute:

[1] We have not included licence drafting associated with the internal incentive proposals at this time to avoid overlapping with the Transmission Price Control Review (TPCR) consultation. Both internal and external incentives licence drafting will be closely coordinated with the TPCR. An informal consultation on the TPCR licence conditions has begun and will continue with a further consultation in early January 2007.

B1. For the purpose of paragraph 8 of Part 2(i) of special condition AA5A, the terms MTt, SFt and CBt in respect of the relevant year t commencing on 1 April 2007 shall be selected against the appropriate value of IBCt (which shall be determined in accordance with paragraph 9 of special condition AA5A) from the following table:

IBCt (£)	MTt (£)	SFt	CBt (£)
<373,333,333	0	0	5,000,000
373,333,333 <= IBCt < 440,000,000	440,000,000	0.075	0
440,000,000 <= IBCt < 490,000,000	440,000,000	0.10	0
>= 490,000,000	0	0	-5,000,000

Option 2

1.7. The amendments to Schedule A (Supplementary Provisions of the Charge Restriction Conditions), Part B (Terms used in the balancing services activity revenue restriction) Paragraph B1 of NGET's Transmission Licence are shown below. Note that there is a different term for TADJt depending on whether the 'statistical' or the 'categorisation' option is included.

1.8. For existing paragraphs B1 and B2, substitute:

B1. For the purpose of paragraph 8 of Part 2(i) of special condition AA5A, the terms MTt, SFt and CBt in respect of the relevant year t commencing on 1 April 2007 shall be selected against the appropriate value of IBCt (which shall be determined in accordance with paragraph 9 of special condition AA5A) from the following table:

IBCt (£)	MTt (£)	SFt	CBt (£)
< FloorIBCt	0	0	UCBt
FloorIBCt <= IBCt < Targett	Targett	USFt	0
Targett <= IBCt < CapIBCt	Targett	DSFt	0
>= CapIBCt	0	0	DCBt

Where:

UCBt = 5,000,000
DCBt = -5,000,000
USFt = 0.075
DSFt = 0.05

B2. For the purpose of paragraph B1:

(a) the value of the terms FloorIBCt, and CapIBCt in respect of the relevant period t shall be given by the following formulae:

FloorIBCt = Targett - (UCBt/USFt)
CapIBCt = Targett + (DCBt/DSFt)

(b) the value of the term Targett in respect of the relevant year t commencing 1 April 2007 shall be shall be selected against the appropriate value of WPt from the following table:

WPt	Targett
<WP0(1-WPVt)	Target0-TADJt [WP0(1-WPVt) - WPt]
WP0(1-WPVt) <= WPt < WP0(1+WPVt)	Target0
>=WP0(1+WPVt)	Target0+TADJt [WPt - WP0(1+WPVt])

Where:

Target0 430,000,000

WP0 is the baseload forward wholesale electricity price for the period 1 April 2007 to 31 March 2008 as given by the April 07 annual package price published by Heren in Edem on 30 March 2007

WPt means the outturn baseload wholesale price for the period 1 April 2007 to 31 March 2008 as given by the average Heren day-ahead price for the period 1 April 2007 to 31 March 2008

WPVt 0.10

TADJt 3,500,000 (statistical option) or 4,700,000 (categorisation option)

Option 3

1.9. The numerical amendments to Schedule A (Supplementary Provisions of the Charge Restriction Conditions), Part B (Terms used in the balancing services activity revenue restriction) Paragraph B1 of NGET's Transmission Licence are shown below.

1.10. For existing paragraph B1, substitute:

B1. For the purpose of paragraph 8 of Part 2(i) of special condition AA5A, the terms MTt, SFt and CBt in respect of the relevant year t commencing on 1 April 2007 shall be selected against the appropriate value of IBCt (which shall be determined in accordance with paragraph 9 of special condition AA5A) from the following table:

IBCt (£)	MTt (£)	SFt	CBt (£)
<396,666,667	0	0	10,000,000

396,666,667 <= IBCt < 430,000,000	430,000,000	0.30	0
430,000,000 <= IBCt < 496,666,667	430,000,000	0.15	0
>= 496,666,667	0	0	-10,000,000

Option 4

1.11. The numerical amendments to Schedule A (Supplementary Provisions of the Charge Restriction Conditions), Part B (Terms used in the balancing services activity revenue restriction) Paragraph B1 of NGET's Transmission Licence are shown below.

1.12. For existing paragraph B1, substitute:

B1. For the purpose of paragraph 8 of Part 2(i) of special condition AA5A, the terms MTt, SFt and CBt in respect of the relevant year t commencing on 1 April 2007 shall be selected against the appropriate value of IBCt (which shall be determined in accordance with paragraph 9 of special condition AA5A) from the following table:

IBCt (£)	MTt (£)	SFt	CBt (£)
<375,000,000	0	0	20,000,000
375,000,000 <= IBCt < 415,000,000	415,000,000	0.50	0
415,000,000 <= IBCt < 515,000,000	415,000,000	0.10	0
>= 515,000,000	0	0	-10,000,000

Transmission losses

1.13. In Chapter 2, we outlined an alternative approach to the calculation of transmission losses for the 2007/08 external SO incentive scheme. This would involve calculating an ex-post average annual transmission losses reference price (rather than the existing ex-ante price), which would then be applied to the difference between actual transmission losses and the ex ante target agreed under the scheme.

1.14. The calculation of the transmission losses adjustment terms in IBC could be based on an ex post reference price by modifying Schedule A (Supplementary Provisions of the Charge Restriction Conditions) Part B (Terms used in the balancing services activity revenue restriction) of NGET's Transmission Licence, as follows:

1.15. For the first sentence of paragraph B3, substitute:

B3. For the purpose of paragraph 9 of Part 2(i) of special condition AA5A, the term TLRPj in respect of each settlement period during relevant period t shall have the value given by the average Heren day-ahead price for the period 1 April 2007 to 31 March 2008.

Gas - external

1.16. Our initial proposals on changes to the gas shrinkage incentive will require a modification to Special Condition C8B[2] of the NGG's NTS licence. Specifically, the proposal will require a change to term GVTPt (the NTS SO gas target volume in respect of year t).

1.17. The proposed change in definition is as follows:

GVTPt means the NTS SO gas target volumes in respect of formula year t and will be defined in line with Table A below

The value of GVTPt is dependant upon the level of SFAFt, where SFAFt means the average daily gas flows through the St. Fergus NTS entry terminal in formula year t=1 (i.e. 1 April 2007 to 31 March 2008).

Table (A)

SFAFt mcm/day	GVTPt (GWh)
SFAFt > 100	8312
85 ≤ SFAFt ≤ 100	7129
SFAFt < 85	6393

[2] This drafting reflects the current condition C8B, and does not yet reflect changes as part of the TPCR (in which this condition is now C8F). Changes to align with TPCR will be fully reflected in the licence consultation draft consultation in January 2007.

Appendix 10 - Internal Incentives Schemes - further information

NGG Internal SO Incentives

1.1. Table 1 reflects our initial proposals for NGG NTS SO internal cost incentives over the period 2007/08 to 2011/12. The first part of the table shows the roll forward of the RAV and resultant capex revenue on our proposed capital expenditure allowance. The second part shows all revenues that NGG NTS will be allowed to recover under the internal cost incentive for 2007/08 to 20011/12. Note that we have not profiled any of the allowances.

Table 1: Regulatory Asset Value and Allowed Items (2007/08 to 20011/12)

2004/05 prices		**2007/08**	**2008/09**	**2009/10**	**2010/11**	**2011/12**	**Five Year Total**
		£m	£m	£m	£m	£m	£m
Regulatory Asset Value							
Opening Asset Value		39.8	46.9	48.5	48.1	52.0	
Total Capital Expenditure		12.8	8.3	6.5	10.8	10.3	48.7
Depreciation	1	5.7	6.7	6.9	6.9	7.4	
Closing Asset Value		46.9	48.5	48.1	52.0	54.9	
Return On RAV	2	1.9	2.1	2.1	2.2	2.4	
Capex Revenue		7.6	8.8	9.1	9.1	9.8	44.3
Allowed Items							
Operaing costs		24.3	23.3	25.4	24.7	24.4	122.1
Capex Revenue		7.6	8.8	9.1	9.1	9.8	44.3
Pensions Allowance		6.7	6.9	6.8	7.1	7.1	34.6
Tax Allowance		0.2	0.6	0.5	1.0	1.1	3.4
							-
Total Internal Revenue		**38.8**	**39.6**	**41.8**	**41.9**	**42.3**	**204.4**

Notes
1 A common asset life of seven years has been assumed for IT and Telemetry Assets
2 Assumes post tax WACC of 4.4% consistent with TPCR Final Proposlas

NGET Internal SO Incentives

1.2. Table 2 outlines the calculation of revenues for non incentivised capex and BETTA implementation capex (sunk investments that continue to be depreciated on a straight-line basis). The table also shows the roll forward of the incentivised RAV and resultant capex revenue based on our proposed capital expenditure allowance. The final section shows all revenues that NGET will be allowed to recover under the incentive for 2007/08 to 2011/12. Note that we have not profiled any of the allowances.

Table 2: Additional capex data and Allowed Items (2007/08 to 20011/12)

2004/05 prices		2007/08 £m	2008/09 £m	2009/10 £m	2010/11 £m	2011/12 £m	Five Year Total £m
Non Incentivised Capex							
Opening Asset Value	1	32.2	18.4	17.8	17.3	16.7	
Total Capital Expenditure		-	-	-	-	-	
Depreciation	2	15.6	0.6	0.6	0.6	0.6	
Closing Asset Value		18.4	17.8	17.3	16.7	16.2	
Return On RAV	3	1.1	0.8	0.8	0.7	0.7	
Non Incentivised Capex Revenue		16.7	1.4	1.4	1.4	1.4	22.3
BETTA Implementation Capex							
Opening Asset Value	4	16.3	13.6	10.9	8.1	5.4	
Total Capital Expenditure		-	-	-	-	-	-
Depreciation	5	2.7	2.7	2.7	2.7	2.7	
Closing Asset Value		13.6	10.9	8.1	5.4	2.7	-
Return On RAV	3	0.7	0.5	0.4	0.3	0.2	-
BI Capex Revenue		3.4	3.3	3.1	3.0	2.9	15.7
Incentivised Capex							
Opening Asset Value		43.3	48.2	48.8	50.2	50.4	
Total Capital Expenditure		11.1	7.5	8.3	7.4	6.7	41.0
Depreciation	5	6.2	6.9	7.0	7.2	7.2	
Closing Asset Value		48.2	48.8	50.2	50.4	49.9	
Return On RAV	2	2.0	2.1	2.2	2.2	2.2	
Incentivised Capex Revenue		8.2	9.0	9.2	9.4	9.4	45.2
Allowed Items							
Operaing costs		50.9	50.1	49.1	50.3	50.1	250.5
Total Capex Revenue		28.3	13.7	13.7	13.8	13.7	83.1
Pensions Allowance		15.6	15.4	15.1	15.1	15.0	76.2
Tax Allowance		0.0	0.0	0.5	0.4	0.9	1.7
Total SO Internal Revenue		94.8	79.2	78.3	79.6	79.6	411.52

Notes
1 Comprises IT and propertym the value transferred at 2001/02 was £130m (04/05 pric
2 Asset lives IT 7 years and Property 40 years, IT asset are fully deprecaited by 2007/0
3 Assumes a post tax WACC of 4.4% consistent with TPCR Final Proposlas
4 See 279/04 Transmission Controls and BETTA: Final Proposals, December 2004
5 Asset life for IT assets is 7 years

Appendix 11 - NGG's Performance under the SO information incentives

1.1. This appendix provides an overview of NGG's performance with regard to its quality of information incentives in the first month of their operation from 1 October 2006. These incentives relate to both accuracy of day ahead gas demand forecasting and performance of NGG's website.

1.2. We intend to publish performance data relating to NGG's quality of information incentives on a monthly basis through winter 2006/07 (as and when it comes available). We encourage respondents to use this information to inform their responses to this consultation.

1.3. Note that more details on the definition of these incentives (including worked examples) can be found in the July 2006 Final Proposals consultation[1].

Demand Forecast data

1.4. Table 1 below shows the accuracy of NGG's D-1 demand forecast (published by 14:00) in October 2006. Error figures show the absolute difference between forecast and actual demand as a percentage of the latter.

1.5. As illustrated in the table below, the October error was 3.52% (a 5.07% year on year fall in the accuracy of its day-ahead demand forecast).

Table 1: Summary of Monthly Average Absolute D-1 UNC 14:00 Demand Forecast Error (%)

Month	Monthly performance 2005/06	Monthly performance 2006/07	Cumulative performance 2005/06	Cumulative performance 2006/07	Monthly % improvement on 2005/06
October	3.35%	3.52%	3.35%	3.52%	-5.07%
November	2.60%				
December	4.63%				
January	3.92%				
February	2.73%				
March	4.02%				

[1] Potential new System Operator quality of information incentive schemes for National Grid Gas, Final proposals and statutory licence consultation, Ofgem, July 2006, 122/06.

Website performance data

1.6. The performance of NG's website was also measured over October 2006. The availability element of the data was collated by an independent website auditor.

1.7. Table 2 below shows the audited record for this link in terms of availability and timeliness in publication of the relevant information.

Table 2: NGG Website Timeliness and Availability Report - Data[2]

NGG Website Timeliness and Availability Report - Data													01-Oct-06 to 31-Oct-06			
	Availability: Downtime (Minutes)				Availability: Uptime (%)				Timeliness: Publication Times Exceeded (All Reports #/24 / SISR03 #/6)				Timeliness: Publications On Target (%)			
Date	NTSAFF	NTSAPF	NB92	SISRO3	NTSAFF	NTSAPF	NB92	SISR03	NTSAFF	NTSAPF	NB92	SISR03	NTSAFF	NTSAPF	NB92	SISR03
01/10/2006	0	0	0	0	100	100	100	100	1	1	1	1	95.83	95.83	95.83	83.33
02/10/2006	0	0	0	4	100	100	100	99.71	0	0	1	1	100	100	95.83	83.33
03/10/2006	0	0	0	0	100	100	100	100	0	0	1	0	100	100	95.83	100
04/10/2006	8	0	0	4	99.44	100	100	99.71	1	1	0	0	95.83	95.83	100	100
05/10/2006	0	0	0	0	100	100	100	100	0	0	0	0	100	100	100	100
06/10/2006	0	0	0	0	100	100	100	100	0	0	0	0	100	100	100	100
07/10/2006	0	4	0	0	100	99.7	100	100	0	0	0	0	100	100	100	100
08/10/2006	0	0	0	0	100	100	100	100	0	0	0	1	100	100	100	83.33
09/10/2006	4	0	0	0	99.7	100	100	100	0	0	0	0	100	100	100	100
10/10/2006	0	0	0	0	100	100	100	100	0	0	0	1	100	100	100	83.33
11/10/2006	0	0	0	4	100	100	100	99.7	0	0	0	0	100	100	100	100
12/10/2006	0	0	0	0	100	100	100	100	1	0	0	0	95.83	100	100	100
13/10/2006	0	0	0	0	100	100	100	100	0	0	0	0	100	100	100	100
14/10/2006	0	0	0	0	100	100	100	100	0	0	0	0	100	100	100	100
15/10/2006	4	0	0	0	99.7	100	100	100	0	0	0	0	100	100	100	100
16/10/2006	4	0	0	0	99.71	100	100	100	0	0	0	0	100	100	100	100
17/10/2006	0	0	4	0	100	100	99.7	100	0	0	0	0	100	100	100	100
18/10/2006	0	0	0	0	100	100	100	100	0	0	1	0	100	100	95.83	100
19/10/2006	0	0	0	0	100	100	100	100	0	0	0	0	100	100	100	100
20/10/2006	0	0	0	0	100	100	100	100	0	0	0	0	100	100	100	100
21/10/2006	0	4	0	0	100	99.7	100	100	0	0	0	1	100	100	100	83.33
22/10/2006	0	0	4	0	100	100	99.7	100	0	0	0	1	100	100	100	83.33
23/10/2006	0	0	0	0	100	100	100	100	0	0	1	0	100	100	95.83	100
24/10/2006	0	0	0	0	100	100	100	100	0	0	0	0	100	100	100	100
25/10/2006	0	0	0	0	100	100	100	100	0	0	0	0	100	100	100	100
26/10/2006	0	0	0	0	100	100	100	100	0	0	1	0	100	100	95.83	100
27/10/2006	0	0	4	0	100	100	99.7	100	0	0	0	0	100	100	100	100
28/10/2006	0	0	0	0	100	100	100	100	0	0	0	0	100	100	100	100
29/10/2006	0	0	0	0	100	100	100	100	0	0	0	0	100	100	100	100
30/10/2006	8	0	0	0	99.41	100	100	100	0	0	0	0	100	100	100	100
31/10/2006	0	0	0	0	100	100	100	100	1	1	0	0	95.83	95.83	100	100
Total	**28**	**8**	**12**	**12**					**4**	**3**	**6**	**6**				
Average					**99.93**	**99.98**	**99.97**	**99.97**					**99.46**	**99.6**	**99.2**	**96.77**

1.8. This table shows that NGG's website has performed well in October 2006, on the basis of the availability and timeliness measures chosen for inclusion in the website incentive.

[2] For definitions of the terms in this table, please refer to the glossary of 'Potential new System Operator quality of information incentive schemes for National Grid Gas: 14 July 2006', http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/15751_12206.pdf.

1.9. In terms of availability, NGG has a benchmark of 362 minutes of average downtime for the four data fields monitored over winter 2006/07. In October, NGG's website registered average downtime for these four data fields of 15 minutes (i.e. below the 60.3 minutes benchmark that a straight monthly allocation would imply).

1.10. In terms of timeliness, website performance has also exceeded the specified benchmark. For winter 2006/07, the timeliness benchmark is for 51.5% of data postings to be "timely." NGG's average performance across the four data fields monitored is 98.76%.

Appendix 12 - Draft Terms of Reference for the review of SO incentives

1.11. We have indicated that during 2007 we will be undertaking a fundamental review of existing system operator (SO) incentive schemes that apply to electricity and gas transmission in Britain.

1.12. The objective of the review will be to examine the effectiveness and appropriateness of existing SO incentive arrangements in order to develop a multi-year SO incentive scheme for the period from 1 April 2008. Such a period may be until 31 March 2012 (the remaining duration of the next transmission price control period). To the extent possible, this review will take into account the outcome of the forthcoming cash-out review.

1.13. The draft terms of reference that we believe should guide our review, and on which we would like to invite feedback from interested parties, are as follows:

- Have previous SO incentive schemes been effective in ensuring that NGET and NGG as SOs have:
    - operated the electricity and gas transmission systems in an efficient and economic manner?
    - managed the external and internal costs of operating the system effectively?
- Are there areas in which previous SO incentive schemes could be enhanced to improve further the incentives on NGET and NGG to operate the electricity and gas networks in an efficient and economic manner, and manage the external and internal costs of operating the system more effectively?
- Is the current scope of the incentive schemes appropriate? For example, should the scope be expanded to include offshore transmission or gas quality? Are there elements that are currently included in the scheme which should be taken out?
- Have the rewards and penalties incurred by NGET and NGG in performing their SO roles appropriately reflected the risks faced by NGET and NGG in performing their respective SO roles, and the capital invested by each in providing SO services?
- Would longer term SO incentive schemes provide greater opportunities for investment that ought over the longer term result in greater net efficiencies in SO costs?
- Do the emerging policy directions in the European Union and/or Great Britain potentially impact the operation of the high-voltage electricity and national gas transmission systems, and therefore impact the SO incentive schemes?

- Is it desirable for SO incentives schemes in electricity and gas to be consistent? Do the physical characteristics of electricity and gas transmission and SO activities limit the extent to which SO incentive arrangements in electricity and gas can be harmonised?

- Is there sufficient transparency surrounding the SO incentives both in terms of the process for setting the incentive parameters and in terms of the information on costs provided by NGET and NGG?