Appendix 2. National Grid's Forecast of Incentivised Balancing Costs for Great Britain in 2006/7

This document is prepared to support the revised forecast submission presented to Ofgem on 6th January 2006. This revision has been developed to replace the original BSIS 2006/07 forecast, which was formally withdrawn by National Grid and published by Ofgem on 22nd December 2005. As such, the revised forecast and this document should be considered to be National Grid's current view of BSIS cost forecasts for 2006/07.

2.1 Introduction and Assumptions

This appendix presents our forecast of Incentivised Balancing Costs (IBC) for Great Britain in 2006/7.

In developing this IBC forecast, we continue to apply and enhance our existing forecasting models, as developed last year for BETTA. The forecast process starts from a breakdown of historical balancing costs. We then consider how these costs might change in the future – that is, we extrapolate future cost scenarios based on experience of past patterns of costs, and on known market changes into next year.

This appendix begins by explaining the forecast method, and then looks at the historic performance of the drivers of IBC, and our seven scenarios, which cover a wide range of possible balancing conditions for 2006/7. The appendix then discusses each element of the forecast, before presenting the overall forecast of GB balancing costs for 2006/07.

Assumptions

We assume in our forecasts that:

- The general scope and form of the incentive scheme remains as BSIS for 2005/6 Great Britain.
- There are no cost levels assumed for any specific Income Adjusting Events (for 2005/6, we have IAEs on the costs of Scottish constraints, and the on-costs of CAP047).
- Transmission Losses is 'net' within the scheme; where necessary, the Transmission Losses Reference Price (TLRP) is £29/MWh.
- There are no other BSC modifications or CUSC amendments, beyond those already approved, that would have a material impact on GB balancing costs.
- There is no explicit inclusion of costs resulting from the implementation of CAP048 (Firm Access and Temporary Physical Disconnection) or CAP070 (Short Term Firm Access).

2.2 Forecasting Method

We have to forecast the term IBC, which is defined in NGET's transmission licence as:

IBC = CSOBM – NIA[1] + BSCC + TLA[2]

[1] 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.
[2] The Formal Licence definition includes the terms OM and RT, which are both forecast to be £0 for 2005/06 and 2006/07.

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 is a scenario based extrapolation method. Constraint costs are forecast, by scenario where required, through a combination of detailed network analysis, risk assessment and probabilistic modelling as described in section 2.7.

We consider that GB IBC is primarily driven by the following cost drivers:

- Forward electricity prices
- BM Prices – average accepted BM bid and offer prices
- Net Imbalance Volume (NIV) or Market Length
- Free Headroom – the level of part-loaded plant delivered by the market at gate closure
- Plant Margin
- Flows across the Anglo – French Interconnector
- Flows from Scotland to England

There are other cost drivers that influence GB IBC but are not explicitly included as one of the key cost drivers because they feed directly into the cost drivers mentioned above. For example, fuel prices directly affect both forward electricity and submitted BM bid/offer prices.

Different drivers impact on balancing costs in different ways. For example, market length or NIV impacts primarily on energy balancing costs in the BM and our forward trades. Free headroom mainly affects system balancing costs; especially warming in Ancillary and margin in the BM. Market length and free headroom also combine to produce a much larger effect on IBC.

The historical and future performance of the above key cost drivers is an important factor in our scenario formulation and forecasting process. This is described in the following section.

2.3 Historic Driver Performance

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 sum of system and energy balancing actions taken by National Grid in the Balancing Mechanism and pre-Gate Closure.

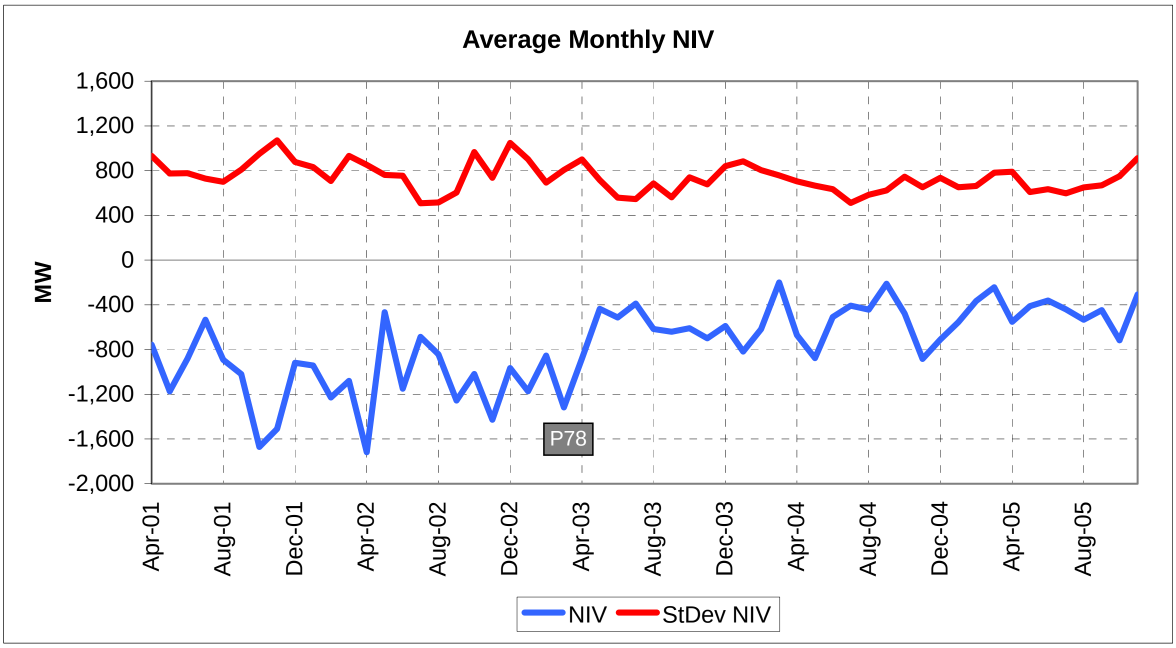
NIV directly determines the volume, and hence the costs, of bids and offers which National Grid has to take to balance the market. It also affects the operating margin available to us at Gate Closure.

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

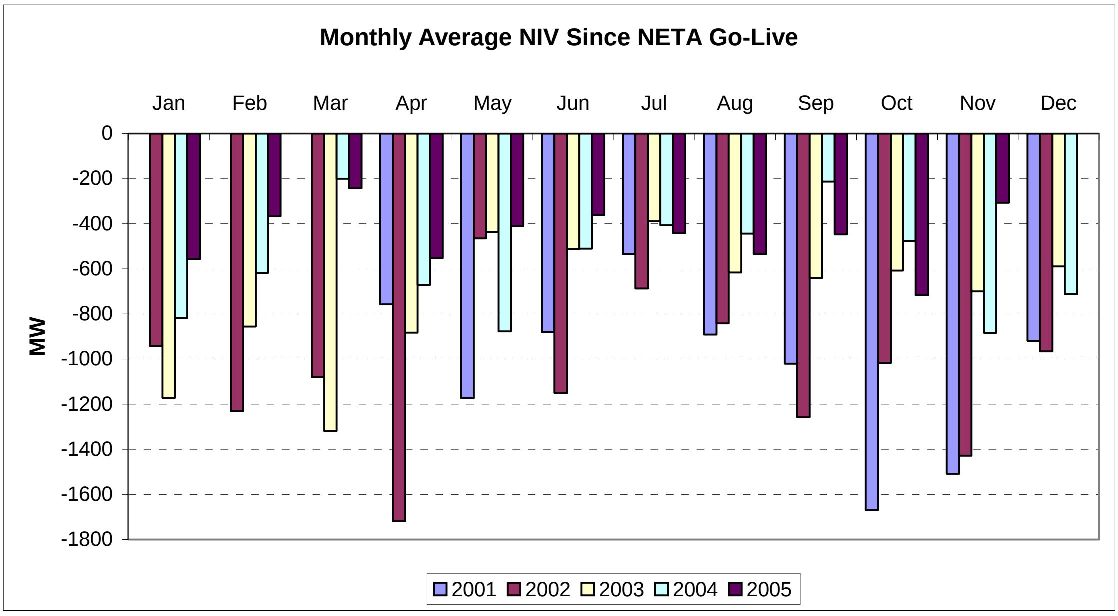
- demand forecasting accuracy,
- risk profile, and
- risk management strategy.

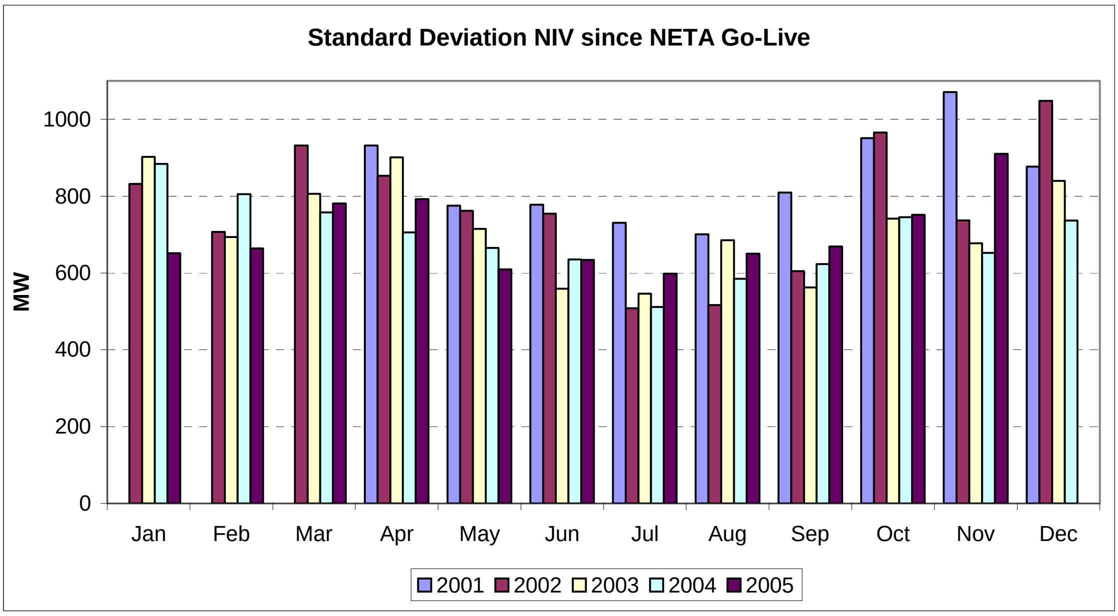
In the majority of Settlement Periods NIV - which approximately follows a Normal distribution - is negative, indicating a long market that National Grid must resolve by taking bids in the BM. This pattern reflects the asymmetric risks faced by suppliers associated with the current dual cash-out pricing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

The market became significantly less long after the adoption of BSC modification P78 (revised definitions of System Buy Price and System Sell Price) in March 2003. In contrast, the standard deviation of NIV has barely changed in the same time period, implying the market has become more efficient as a result of reduced risks, rather than improved demand forecasting by suppliers.



Contrary to our expectation, the market has not become slightly longer after the introduction of BETTA, which increased the size of the market by some 11%. The monthly average NIV between Apr-05 and Nov-05 (-472MW) is nearly 20% down on the same period last year (we note however that May-04 and Nov-04 were particularly long).



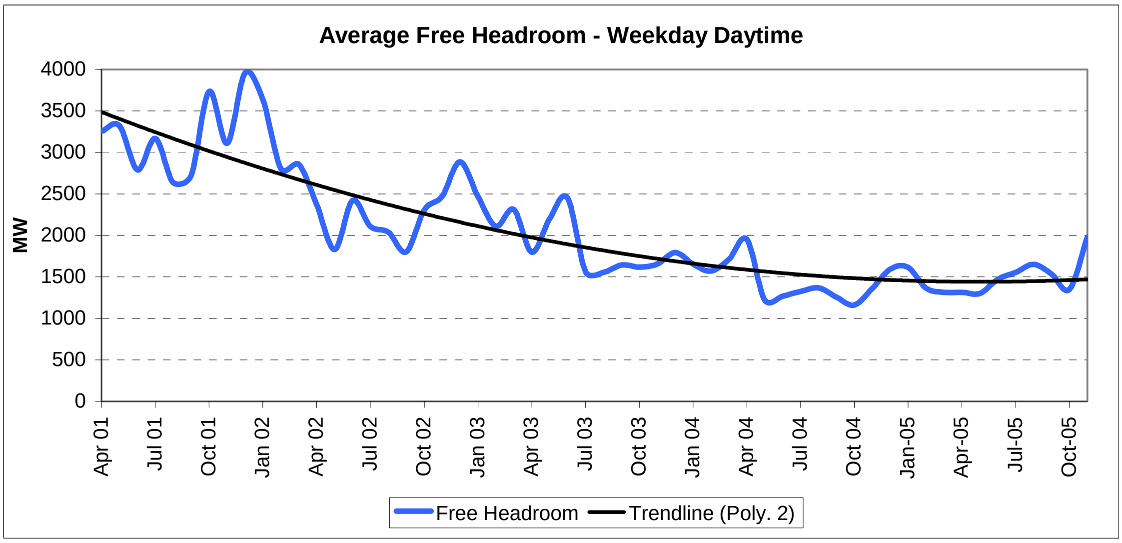


Free Headroom

Free Headroom is the volume (MEL minus PN) across part-loaded plant, delivered by the market at Gate Closure. It can also be thought of as the sum of spare capacity across all running generators.

Headroom delivered without actions on National Grid's part contributes to meeting our short-term system operating margin requirements, and therefore the level of free headroom directly impacts on the cost of Margin.

Free headroom displays a clear downward trend since the implementation of NETA until the advent of BETTA. Over this time we have seen a typical year-on-year reduction in free headroom of some 25%. This trend suggests the market is becoming more efficient, with fewer part-loaded plants on the system, and a reduced amount of plant available to provide system reserve. There has also been a small measure of market consolidation, and this may have served to reduce plant part-loading.



The fall in free headroom can be seen to have moderated after the introduction of BETTA. We had anticipated this, given that the 11% increase in the size of the market could have been expected to deliver extra headroom. Our expectation is that the gentle underlying downward trend will continue until a natural minimum is attained. This natural minimum level of free headroom will be determined by the degree of competition in the BM and generators' risk management policies.

Electricity Forward Price

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

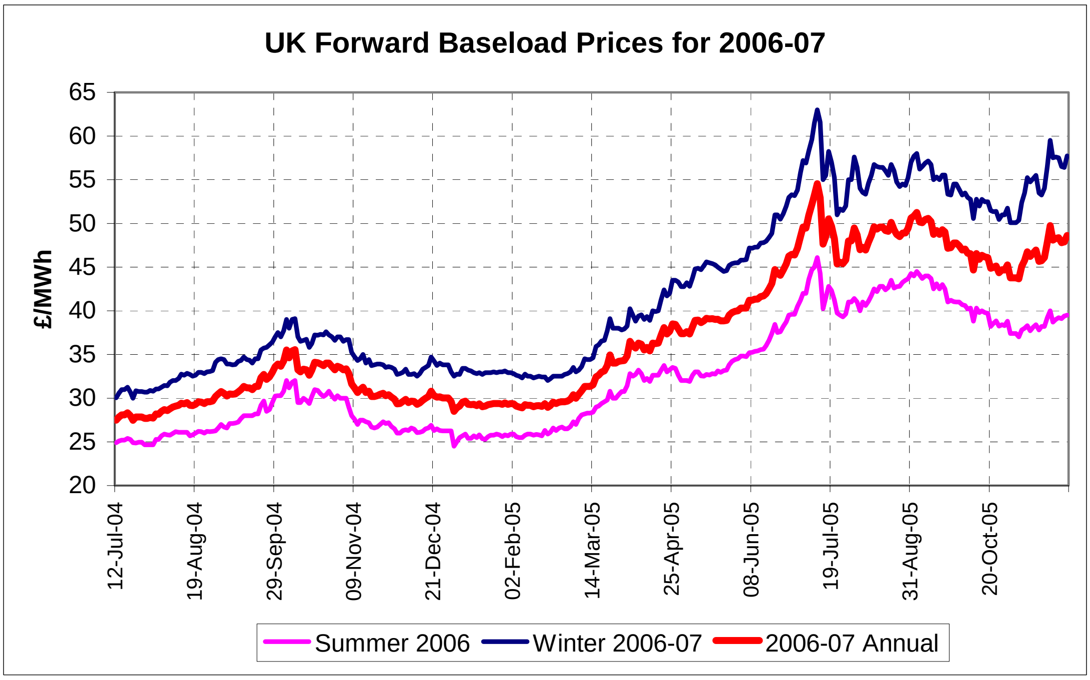
Since March 2005 the forward price of electricity for summer 2006 and winter 2006/07 has increased markedly. Summer baseload has increased from some £30/MWh in Feb-05 to greater than £40/MWh by Nov-05, having peaked at £45/MWh in July. The winter baseload forward price has increased from £33/MWh in Feb-05 up to £55/MWh by end Nov-05, having peaked at £63/MWh in July. We note that the reduction from the peak prices seen in July was rapid, but that the prices have been broadly stable at their elevated levels since then.

Key factors behind these price movements are

- significant increases in fuel prices (particularly gas);

- the introduction of the EU ETS and an increasing carbon cost (which particularly affects coal plant).

The current forward price for 2006/07 annual baseload is £56/MWh[3]; we note that this is, above our scenario mean annual price of £49/MWh.



BM Prices

Prices in the Balancing Mechanism directly impact on the costs of system and energy 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.

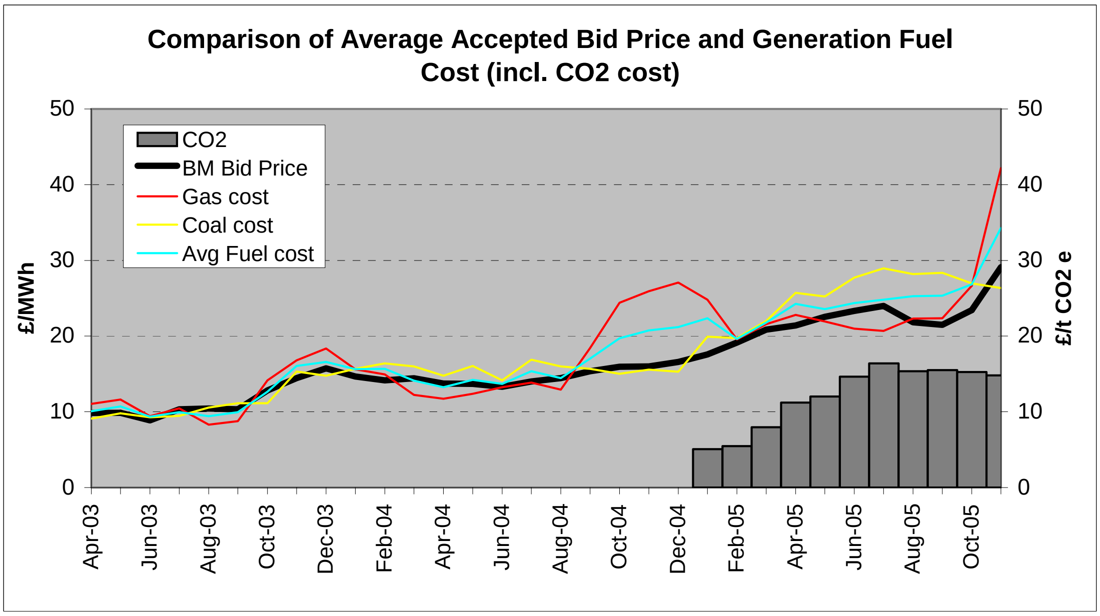
The BM bid market is highly competitive, with a large volume of bids accepted by National Grid principally for energy balancing. By Mar-05 the average accepted bid price rose to consistently greater than £20/MWh, and by Nov-05 was approaching £30/MWh. This is explained by variations in the cost of the marginal fuel (recently gas) and the introduction of the EU ETS, which saw the cost of carbon increase threefold (to some 15 £/t CO_2e). For coal generators in particular it has become very attractive to be bought of the system, leading to upward pressure on bid prices. With the arrival of the EU ETS, it is clear that bid prices do in fact track total generation costs, rather than merely fuel prices.

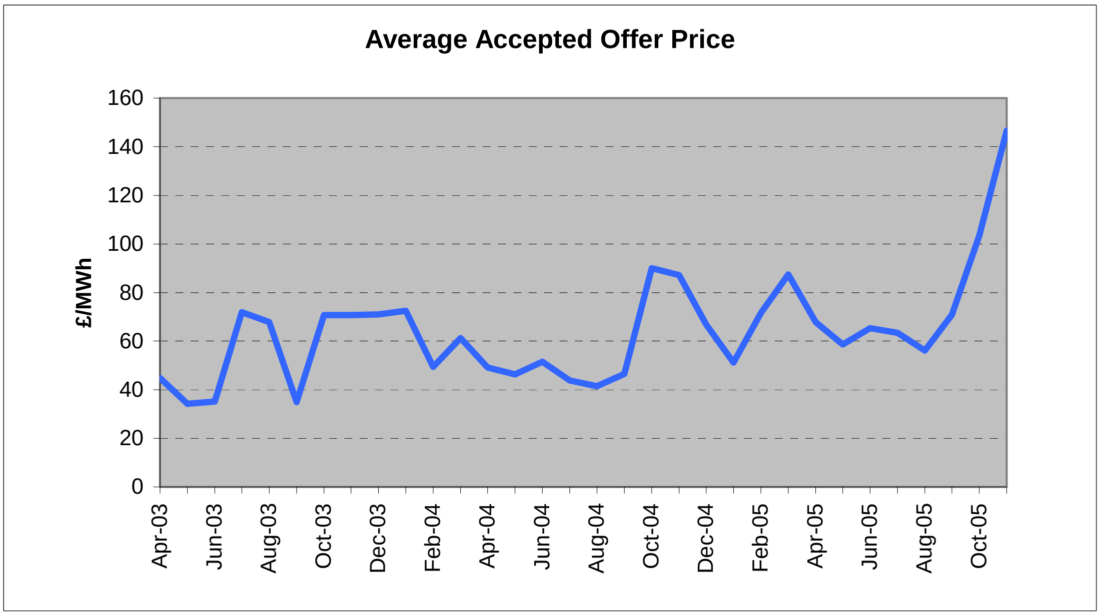
In contrast, the average accepted BM offer price is highly volatile from month to month. This is since it depends upon on the prevailing market conditions and the extent of actions taken by National Grid for margin and constraints. The offer price is

[3] Argus European Electricity Report, 4th January 2006.

seasonal in that it has historically always been highest in winter, when lower-merit plant is marginal.

Since the introduction of BETTA, accepted offer prices have ranged over £55-70/MWh, slightly above the levels of summer 2004. In October 2005 average accepted offer prices breached the £100/MWh mark for the first time, and in November increased further to over £140/MWh - by far the highest monthly price since the start of NETA. We consider the price movement in November 2005 to be a reflection of typical variations in weather and tight market conditions in this one month – we do not anticipate offer prices at these values over a whole season in any of our forecast scenarios.





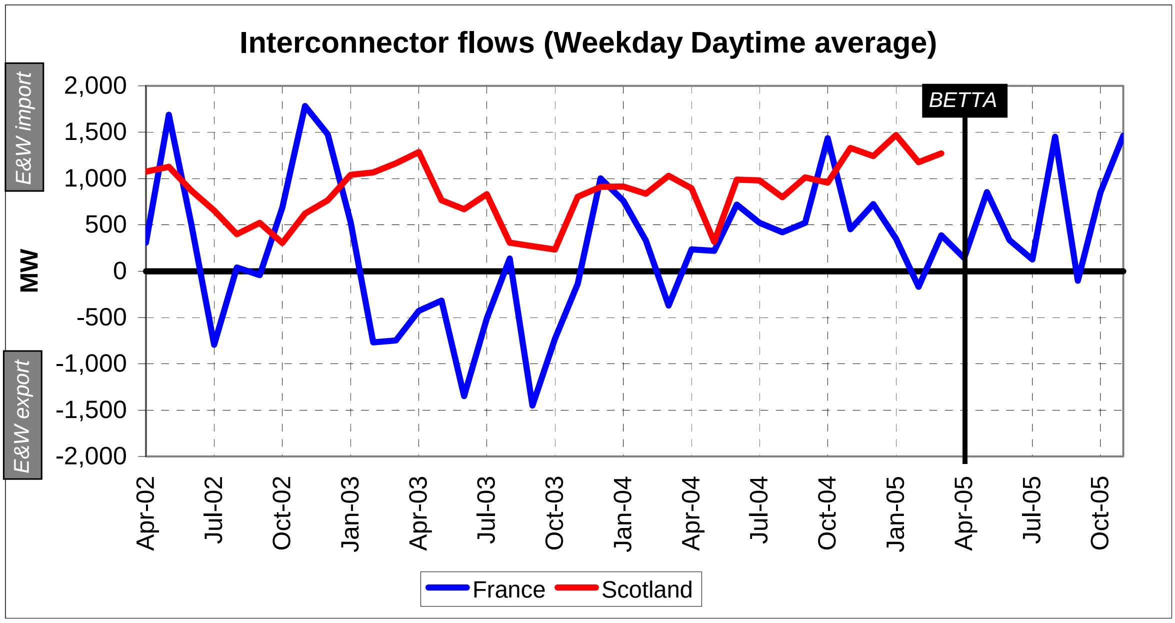
Interconnector Flows

Flows across the Anglo-French interconnector depend primarily upon the price differentials between E&W and continental Europe. UK export to France can potentially have a significant impact on constraint costs across the south and south east of the system.

During summer 2003 forward prices in E&W were somewhat lower than European prices. Since E&W prices are now higher than in Europe, French interconnector transfers have moved away from the high levels of UK export seen in 2003 to moderate UK import.

Whilst French interconnector flows may reach the nominal 2GW maximum export limit for some days, or certain periods of the day, the average flow for weekday daytime[4] is very unlikely to approach this level. This is a result of the different within-day price profiles in the UK and in Europe (and also because of planned link outages). Indeed, it can be seen that the average monthly weekday daytime interconnector flow has only exceeded 1GW UK import for six months since Apr-02.

The Scottish interconnector became part of the GB transmission system with the introduction of BETTA. "Scottish transfer" data post-BETTA is no longer compatible with pre-BETTA sources, and is not shown here. Nevertheless it is apparent that in the run-up to and final month before BETTA, the weekday daytime transfers from Scotland were among the highest in recent years, alerting us to the possibility of significant Cheviot constraint costs.



[4] Here defined as EFA blocks 3+4+5, 0730-1900, Monday – Friday.

2.4 Scenarios

We have developed a robust scenario construction process. This involves careful analysis and monitoring of key cost driver performance (as described in section 2.3 above), reviewing market developments, and collation of market intelligence.

In order to forecast GB balancing costs, we have constructed seven credible scenarios, reflecting the likely range of market conditions and participant behaviours in 2006/07. These scenarios form the basis of our forecast. Each scenario is considered independently and represents a possible market condition, though some are assigned a higher probability of occurrence than others.

Scenario Characteristics

Scenario 1 – "Cheap Fuel"
In this scenario, oil and gas prices moderate down by 35%, to 2004 levels. As a consequence of increased CCGT running, the carbon price halves to 12 €/tCO2e. Electricity base-load price averages 32 £/MWh. There are no significant changes to the electricity market structure –ie to the 'big six'–, and there are no plant closures despite the lower generator profitability. British prices undercut Europe, leading to strong flows from GB to Europe. The market becomes 20% longer than now, because Suppliers can afford cover at the cheap prices. Free headroom is high, under Generator competition in the BM.

Scenario 2 – "Mild Year"
In a mild year, oil and gas prices fall from current levels, but remain above 2004 levels. The cost of carbon moderates to 15 €/tCO2e. Electricity baseload price falls to 38 £/MWh. There is modest further consolidation in the market, eg with some further acquisitions of small independent stations. The market is cautious and exercises 'self-restraint', with no significant increase in competition or targeting of market share by participants. BM Bid and Offer prices both decline from current levels. The market length increases by 15%, again due to cheaper cover available. Free headroom remains at current levels.

Scenario 3 – "As Now"
Under this scenario, the market behaves 'as now', with no changes in generator ownership. The price of carbon remains at a current level of 20 €/tCO2e, and electricity baseload averages 50 £/MWh. There is no mothballing or closure of plant, and plant margin remains unchanged at 22%. There is no major change in generator behaviour, and Bid prices average 26 £/MWh and Offer prices 85 £/MWh, as now. Gas undercuts Coal in summer, but Coal undercuts Gas in winter. The current level of electricity price dampens market length, and the levels of length observed since April 2005 are maintained throughout 2006/7. Free headroom remains at current levels.

Scenario 4 – "Consolidation"
This scenario is characterised by consolidation of the generation market into fewer vertically integrated players. The consolidation sees the withdrawal of some 1GW of less efficient plant, and a less volatile market. Plant margin is 20%, and forward prices are 47 £/MWh, which in turn exerts an upward pressure on BM prices. Against the background of a less volatile market, suppliers are better able to manage their risk profiles. Market length drops by 15%, and generators achieve further

reductions in free headroom of 20%. Flows from France are volatile, and fall slightly from current levels.

Scenario 5 – "High Fuel Prices"
Under this scenario, a booming world economy sees fuel prices rise significantly, with gas prices up by 25% from current levels. Given that CCGTs are less competitive, the price of carbon rises to 25 €/tCO2e, and electricity baseload averages 60 £/MWh over the year. This forward price discourages suppliers from over-contracting, leading to a fall in NIV of 10%. Free headroom declines by 10%, due to the high cost of holding it. There are no significant market developments in generation or supply, as further mergers are blocked. The plant margin remains at 22% with no closures. Flows from France to GB are high, in response to the high GB prices. There are high flows from Scotland to England, because Scottish coal stations undercut Gas, and run hard.

Scenario 6 – "Uncertainty"
The general theme of this scenario is one of difficult markets under uncertain and volatile conditions. Fuel prices are volatile, with tight supplies worldwide. The price of carbon averages 25 €/tCO2e, and electricity base-load averages 50 £/MWh across a number of price spikes. There are no plant closures, given the uncertainties, and plant margin remains at 22%. BM Offer prices are volatile, averaging 85 £/MWh as now, and BM Bid prices remain at 26 £/MWh. Flows from France remain as now, but only on average. The high price uncertainty encourages Suppliers to over-contract, but this is mitigated by the high forward price of contracting; as a result market length increases by 10%. Free headroom remains unchanged at current levels.

Scenario 7 – "Cold Winter"
This scenario sees high and volatile fuel prices, especially gas, reflecting tight supply conditions in a slightly colder than average winter. The price of carbon averages 25 €/tCO2e, and electricity base-load averages 65 £/MWh across a number of price spikes. There are no plant closures, given the uncertainties, and plant margin remains at 22%. BM Offer prices are volatile, with some extreme spikes, averaging 110 £/MWh, and BM Bid prices are also high at 36 £/MWh. Flows from France remain as now, but only on average. The extremely high price of forward contracting forces Suppliers to increasingly take their chance on imbalance price; as a result market length reduces by 10%. The level of free headroom declines by 20%, because of the lost opportunity cost of holding it.

The table overleaf summarises all of the scenario parameters, and also shows the probability that we have attached to each of them. The scenario probabilities reflect our views on the likelihood of each scenario occurring in 2006/07, taking into account the emerging trends in IBC cost drivers, market developments, and our market intelligence. In our view, these scenarios represent a realistic range of possible outcomes, and the weighted average of the parameters is reasonable against the current background.

DRIVER	Scenario 1 Cheap Fuel 5%	Scenario 2 Mild Year 20%	Scenario 3 As Now 25%	Scenario 4 Consolidation 15%	Scenario 5 High Fuel Prices 20%	Scenario 6 Uncertainty 10%	Scenario 7 Cold Winter 5%
Fuel Prices (Gas p/therm Sum : Win)	Oil and Gas prices moderate world-wide to 2004 levels. Gas 28 : 42	Oil and Gas prices fall, but still remain higher than 2004/05. Winter turns out mild, and the decline in UKCS gas is broadly in line with Winter Outlook Review. Gas 34 : 51.	Remain at current high level. Gas 48 : 80.	Settle at current levels. Gas 42 : 63.	Booming world economy increases energy demands. Gas and oil prices rise significantly: gas 60 : 95.	Fuel prices are very volatile, caused by tight supply and demand situation in the world oil market. Gas 45 : 85.	Fuel prices are high and very volatile, coupled with a tight gas supply situation and a cold winter. Gas at 60 : 110.
Cost of Carbon €/tCO2e	Drops significantly to 12	Moderates to 15, reflecting increased CCGT competitiveness	Stabilises at 20	Stabilises at 20	Rises to 25	Volatile, averaging 25, reflecting underlying uncertainties in carbon emissions and CCGT competitiveness.	Volatile, averaging 25, reflecting underlying uncertainties in carbon emissions and CCGT competitiveness.
Plant Competitiveness	CCGTs become more competitive. Marginal generation becomes slightly more aggressive	Increased CCGT competitiveness	Gas undercuts Coal in summer, but Coal undercuts Gas in winter.	Gas undercuts Coal in summer, but Coal undercuts Gas in winter.	Lower CCGT competitiveness	Higher CCGT competitiveness.	CCGTs extremely uncompetitive
Baseload Electricity Price (Sum : Win)	Falls to £32/MWh (28 : 36)	Falls to £38/MWh (33 : 43)	As now - £50/MWh (42 : 58)	Averages £47/MWh (40 : 54)	Rises to £60/MWh from increase in market competition (50 : 70)	More volatile – averages £50/MWh across the year (40 : 60)	Highly volatile – reaches £65/MWh across the year. (50 : 80)
French Transfers	Flows GB to Europe increase - especially in winter- as British prices undercut Europe	Flows GB to Europe increase slightly, especially in winter	Flows from France are 'as now'	Flows from France are volatile and fall slightly from current levels	Flows from France fall, as the high fuel cost has a bigger impact on European prices.	Flows from France are high, in response to the high GB prices	Flows from France are high, in response to the high GB prices
Market Structure and **Developments**	The market in the second year of BETTA settles into the pattern established in 2004/05. No significant changes.	Modest further consolidation (eg. A portfolio player buys more small stations). Less competition between the 'Big Six'.	Market behaves "As Now", with no large change in generator ownership.	Significant market consolidation in Supply and Generation (e.g. Portfolio player buys Merchant generator). The remaining 'Big Five' control all markets, and command a premium in the forward and BM markets.	No significant market developments in generation or supply, as significant mergers in the power sector are blocked.	No significant market developments .	No significant market developments .
Plant Margin (incl. openings / closures of plant)	Remains at 22% - no closures despite lower profits	Remains at 22% - no closures	Remains at 22% - no mothballing/closures	Falls to 20%. Following mergers, up to 1GW of marginal plant is closed or mothballed.	Remains at 22% - no closures.	Remains at 22% - no closures, given the uncertainty	Remains at 22% - no closures, given the uncertainty
BM Prices (average)	Bids fall to around £20/MWh reflecting the cost of carbon. Offers pushed up by aggressive marginal generation and carbon cost	Bids fall to £22/MWh reflecting lower marginal generation cost. Offers at £72/MWh	Bids remain at £26/MWh. Offers increase to £85/MWh reflecting higher forward prices and cost of Carbon	Bids at £23/MWh. Offers remain at £80/MWh	Bids rise to £34/MWh. Offers rise to £100/MWh as CCGTs become marginal plant and compete aggressively.	Bids rise to £26/MWh. Offers highly volatile, averaging £85/MWh	Bids rise to £36/MWh. Offers highly volatile, averaging £110/MWh
Scottish Generation	Flows from Scotland are 'as now' (after allowing for +2TWh of extra Wind generation).	Low Scottish Coal generation	Flows from Scotland are 'as now' (after allowing for +2TWh of extra Wind generation).	High Scottish flows, as both Scottish coal and gas runs	Low Scottish Gas generation	Low Scottish Gas generation	Scottish flows are high, as Scottish coal runs
Market Length	20% longer, as Suppliers can afford cover at cheap prices	Slightly longer than it is now as suppliers can afford cover at cheap prices - increases by 15%.	The market length seen since April 2005 is maintained throughout the year, but high forward price result in a 10% fall.	15% less long	10% shorter, because of high contract costs	Increases by 10% - High price uncertainties encourage Suppliers to over-contract, but this is mitigated by increased cost of over-contracting arising from high forward prices.	Decreases by 10% - the extreme price of contracting forces Suppliers to take their chance on Imbalance (as seen in Nov 2005).
Free Headroom	High, under GenCo competition in BM	Remains broadly the same as 2004/05. The reduction of Free Headroom in England and Wales plant is offset by Scottish generators	Follows the trend into 2005, and falls by 10% from 2004/05 levels.	The 'Big Five' continue to improve their scheduling and despatch efficiency, and achieve the historical rate of reduction in free headroom - down by 20%	Decreases by 10%, due to the cost of holding it.	Free headroom stays unchanged from the current level.	Decreases by 20% due to the cost of holding it.

2.5 Ancillary Forecast

Historical costs and volumes of Ancillary services[5] are reported in our monthly Procurement Guidelines reports, and extensively to Ofgem. 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 over a base period, namely April 2004 to March 2005. The model then extrapolates both prices and volumes, service-by-service, into the forecast period April 2006 to March 2007

Our mean forecast for Ancillary services is summarised in the table[6] below. The table shows the historic costs of each service for 2001/2 to 2004/5, our projection for 2005/6, and our forecast for 2006/7. The historic years 2001/2 to 2004/5 are on an England & Wales basis, whereas 2005/6 and 2006/7 are on a Great Britain basis.

Summary of Forecast Ancillary Services Costs for 2006/07 (£m)

	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07	Variance to 05/06
Reactive	38.1	33.0	33.5	36.7	58.7	73.6	14.9
Response	63.6	58.2	44.5	44.8	50.5	50.5	0.0
CAP047	0.0	0.0	0.0	0.0	9.5	20.8	11.3
Standing Reserve	20.1	22.5	42.5	48.1	43.9	55.7	11.8
Fast Reserve	16.7	30.8	18.7	25.8	37.2	36.0	-1.2
Other Reserve	6.6	4.5	4.2	5.0	6.3	6.1	-0.2
Warming	9.0	30.4	21.1	16.3	14.9	19.2	4.3
Black Start	9.1	9.8	10.1	10.0	14.7	16.9	2.2
AS Other	6.7	10.7	2.9	1.2	2.6	2.0	-0.6
Total	**169.9**	**199.9**	**177.5**	**187.9**	**238.3**	**280.8**	**42.5**
	(E&W)				**(GB)**		

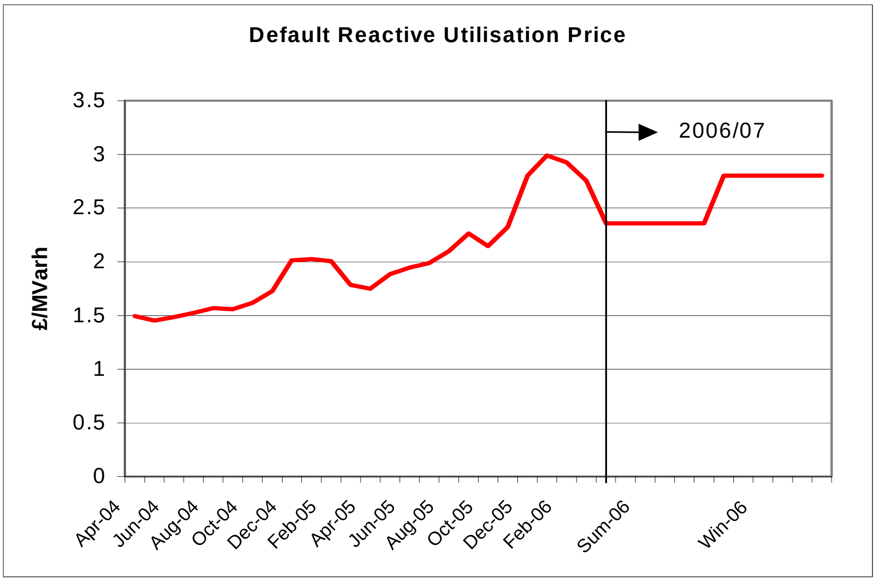
This forecast is now discussed on a service-by-service consideration of costs.

Reactive

The volume of reactive utilisation has increased by 20% since last year, entirely as a result of 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 on this. 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.

[5] The Licence defines the term BSCC – Balancing Services Contract Costs. For our forecasting purpose, we consider this term in two parts: BSCC = Ancillary + Trades. The cost of Trades is considered in section B9, because it interacts so heavily with the costs in the BM. The remaining costs within BSCC are termed Ancillary, because they equate almost exactly with the costs of Ancillary contracts, as defined since Vesting.

[6] This Table excludes the costs of Ancillary Constraints, which are forecast in section B8, and also the energy costs of Ancillary SO-SO trades, which are forecast in section B10.



Following the implementation of CUSC amendment CAP045, the price of default reactive utilisation is now 50% indexed to power prices. Tenders seeking reactive market contracts factor in the full default price into their tendered prices. The chart in section B3 shows the significant rise in power prices over the last 12 months, and our scenarios forecast that on average power prices next year remain at current high forward levels. The effect on reactive default prices is summarised in the chart above. Combining this price increase with the static reactive volume, our mean forecast of reactive costs rises from £59m this year to £74m next year.

Response
Costs for Ancillary Response in 2005/6, including costs of mandatory and commercial contracts but excluding any impact of CAP047, are projected to outturn at £50.5m. Given that we identify no change to the volume of response next year, and that all price effects are considered with CAP047 in section 2.6 below, our forecast for Ancillary Response for 2006/7 remains unchanged at £50.5m.

Standing Reserve
For 2005/6, we have contracted 2255MW of standing reserve capacity, at an ancillary cost projected to be £43.9m. This cost comprises £37.5m of availability fees, plus £3.8m of utilisation payments to non-BM providers paid via Ancillary. We also have contracted 236MW of Supplemental Standing reserve, at a projected cost of £2.6m.

For 2006/7 we have received tenders whose prices have increased by some 9%, with respect to annual availability. This price growth is a function of the interaction of the level of diversity and competition present in the standing reserve market and the current upward trend in margin costs across the system, and is despite increased optimality of service window selection to reduce the total number of contracted hours. The formal tender assessment is still to be completed, however for this forecast we have assumed that it will be economic for us to procure an extra 250MW of the tendered standing reserve capacity for 2006/7. We also forecast to procure a similar volume of supplemental standing reserve for winter 2006/7, at a similar price to 2005/6 – by then, under ARORA proposals, the tenders will be merged into a single 'STORT' product ('Short Term Operating Reserve Tender'). Overall, this increased cost of purchase, at £55.7m for 2006/7, will be approximately offset by reduced costs of margin actions in the BM (see section 2.9 below).

Fast Reserve
Costs for Ancillary Fast Reserve for 2005/6, across firm and optional sources, are projected to outturn at £35.6m. We continue to make considerable use of this service post-BETTA, and the price remains reasonably competitive amongst the limited portfolio of providers. Accordingly, our forecast for Ancillary Fast Reserve for 2006/7 is £36.0m.

Other Reserve
Within Ancillary, we also 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. Allowing for some containment of spend next year, we forecast to spend £6.1m on Ancillary Other Reserve for 2006/7.

Warming
The cost of warming contracts, which keep gensets in a state of dynamic readiness consistent with our Reserve requirements over 24 to 4 hours out, are projected to outturn at £14.9m for 2005/6. For 2006/7, we anticipate the same volume and price of activities by current providers. However, we anticipate that the roll-out of ARORA within-day provisions will result in a transfer of £4m of costs from BM margin acceptances into increased warming payments under new ARORA provisions. In the event that ARORA does not proceed in winter 2006/7, this transfer of £4m will not occur.

Black Start
Costs for Black Start services for GB are projected to outturn at £14.7m this year, and include the costs of Scottish providers, and refurbishment and testing of some existing providers. Factoring in further refurbishment costs, which are already being sought for next year, and the costs of our black start tests, which are increasing in line with power prices, our forecast for Black Start for 2006/7 is £16.9m. 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 Ofgem's initiative on Black Start preparedness.

Constraints and SO-SO Energy
Costs for Ancillary Constraints are subsumed into the forecast of Constraints in section 2.7. Also the costs of 'SO to SO trades' across the French and Moyle Links, which in outturn are reported as an Ancillary cost, are subsumed into the forecast of IBMC+Trades in section 2.9.

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.

2.6 Response Market (CAP047)

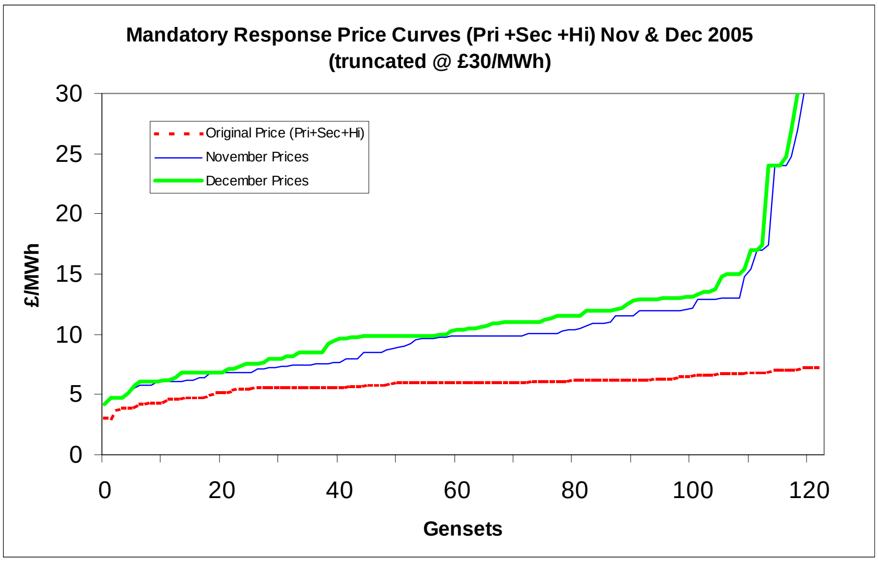
The above forecast of Ancillary costs specifically excludes any effects of CAP047.

CAP047 was approved by Ofgem and implemented during October 2005 such that the first month's new price submissions would be effective from 1st November 2005.

We continue to hold the view that there will be significant cost pressures, once the cost-reflective principle is lifted from Mandatory (Grid Code) response. In this document last year we stated our view that 'assuming reasonable market behaviours, the average response holding prices, including mandatory and commercial prices will rise by 50% from the implementation of CAP047'. Whilst Ofgem agreed that prices could rise, they considered a smaller price rise was more likely and, in line with this Ofgem agreed a £7.35m allowance (equivalent to ~25% price rise) within BSIS 2005/06.

Early indications (November and December 2005 submitted prices) show a significant increase across the vast majority of Mandatory services. The median price increase across the cheapest 120 gensets indicates a 65% rise compared to previous 'cost-reflective' pricing.

The graph below shows the Mandatory price curves (by genset) for the period immediately before CAP047, and for the first two months of submitted prices. The graph is truncated at £30/MWh to enable trends to be seen, and other genset prices above this level are regarded as prohibitively high at this stage.



Price submissions for the first month of CAP047 operation, November 2005, show the largest step change in prices and have lead to additional daily expenditure in the order of £50–60k per day for the first part of the month.

Prices submitted for December 2005 show further (though less pronounced) price increases. December price submissions appear to reflect a smaller number of genset owners seeking greater value than was the case during November. Consequently, it seems likely that the cost trend of November will continue in broad terms.

We expect that, in future months, service providers will continue the pattern already seen and price explore to optimise income. If prices stay at current levels, then a total cost increase for Mandatory Response payments of some £1–2m per month will emerge. If these levels continue then it is likely that the £7.35m on-cost level agreed within BSIS 2005/06 will be exceeded.

In line with this trend in Mandatory pricing, we expect alternative response services to seek enhanced value. When assessing the economic case for accepting such services, we measure them against the existing and expected cost of alternatives. For example, tendered Firm Frequency Response services are already reflecting enhanced value, and our FFR tender assessment takes account of the increase in Mandatory response prices. The on-cost effect of these consequential price rises is likely to be smaller, due to the smaller proportion of Response currently procured through these mechanisms. However, if prices track current Mandatory prices then this would result in a total rise in costs across 2006/07 across all Response procurement in excess of £25m for 2006/07.

For 2006/07 we are forecasting a fall in prices from current levels of ~65% to the equivalent of a ~45% price rise across all Response procurement for 2006/07. Our forecasts for next year use a number of scenarios, some that see prices falling and others that show a continuing, more gradual, increase in prices from current levels. These result in the central expectation of a 45% price rise when compared to pre-CAP047 prices and lead to a total forecast on-cost across all Response procurement of £21m.

Overall, it is clear that the evolution of prices and procurement under the CAP047 Frequency Response pricing modification is uncertain and dependent on a number of different variables, including market perception and participant behaviour. In reflecting these uncertainties within our forecast of £21m, we have arrived at central forecast that sees a decline from the price levels seen currently but that also balances the possibility of prices increasing or decreasing across the year as a whole.

2.7 Constraints Forecast

Assumptions

In producing constraint forecasts, we have made certain assumptions about the GB transmission network, especially in Scotland. The main assumptions are briefly described below:

- The constraint limit across the Cheviot boundary (which is made up of the pre-BETTA Anglo-Scottish interconnector circuits) is typically driven by stability or thermal limitations, with winter limits of 2200MW, and summer limits of 2000MW under intact conditions and 1300MW under outage conditions;
- There are 13 weeks of planned outages in 2006/7 directly affecting the Cheviot boundary.
- The existing operational intertrip schemes within Scotland will continue to be available under BETTA; (e.g. the Ayrshire operational intertrip scheme);
- We gain access to local intertrip schemes at certain key stations, which Ofgem have determined to be commercial intertrips; however, we assume that no intertrip scheme is available for the Cheviot boundary;

- Where possible, the GBSO will be able to move planned outages in Scotland. The costs of shifting such outages are not included in the forecast, but are borne under a different scheme.

We have not included the cost of the following issue within our forecast:

- Islanding Events: In Highlands and Islands areas, such as the Western Isles, where part of the network is separated from the main interconnected system following a fault or under planned outage conditions, an embedded generator is traditionally required to run to maintain local supply.

Generation Background

Based on the information available to us, there are neither closures of existing generation, nor commissioning of new generation, other than new windfarms, in the GB market in 2006/7. One exception is the closure of Sizewell A and Dungeness A stations, which come to the end of their operational life by December 2006.

There is an uncertainty surrounding the number of windfarm projects commissioning in Scotland through to end March 2007. We have carefully reviewed windfarm project developments in Scotland, in terms of their likelihood and timeframe of commissioning. As a result, we estimate that a total of 1100MW of windfarms will be commissioned by mid-summer 2006, and 1450MW will be commissioned by mid-winter 2006/7. We have assumed that the average load factor of wind generation is 30% in the months of April to October (inclusive) and 33% in the months of November to March.

Constraint Forecasting Approach

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

- England & Wales
- Cheviot boundary
- Within Scotland

A consistent approach is used to forecast constraint costs in England & Wales and within-Scotland. This is a bottom-up approach involving detailed studies of the transmission network, based on planned transmission and generator outages, and 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.

Forecasting Constraint Costs across the Cheviot Boundary

Scottish generators are no longer subject to the previous administered interconnector arrangements, and are free to vary their output and operating regimes. This, coupled with recent changes of fuel costs and ownership, makes it likely that there will be changes in the patterns and level of flows across the Cheviot boundary. In addition, the Cheviot boundary constraint is active and well known by market participants, being the subject of a number of studies and Ofgem consultations, and its presence may influence behaviour of itself.

Therefore, there are great uncertainties surrounding the likely constraint costs across the Cheviot boundary primarily due to uncertainties in generator output in Scotland.

In order to estimate the constraint costs across the Cheviot boundary, we have developed a spreadsheet-based annual probabilistic model. It models 12 demand blocks representing the Scottish demand duration curve. Assuming generator behaviour in line with historic experience, we forecast unconstrained Scottish station output by demand block and by scenario. The uncertainties in forecast station output and demand within each scenario are input into the probabilistic model.

The table below summarises forecast unconstrained Scottish generator output.

Station Output (Twh)	Base*	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5	Scenario 6	Scenario 7	Weighted Mean
Nuclear	17.3	17.1	17.1	17.1	17.1	17.1	17.1	17.1	17.1
Thermal	21.5	19.8	18.5	19.5	22.2	20.6	20.0	21.1	20.1
Hydro	4.7	3.6	3.6	3.5	3.5	3.9	3.7	3.9	3.6
Wind	0.0	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6
Total	**43.5**	**44.1**	**42.8**	**43.7**	**46.4**	**45.2**	**44.4**	**45.7**	**44.4**

* Base = 2004/5 data

The mean forecast output of existing power stations in Scotland shows slight decline from the historical level. New wind projects contribute 3.6TWh across all scenarios and total Scottish generation output varies from 42.8TWh in Scenario 2 to 46.4TWh in Scenario 4 reflecting different scenario assumptions.

Cheviot Constraint Prices

The Cheviot boundary mainly restricts flows from Scotland to England & Wales. The price of the constraints is determined by the Bid prices submitted by Scottish generators, and by the replacement prices in England & Wales.

We represent Scottish Bid prices within our model using probabilistic techniques. Scottish Bid prices are modelled such that they track the underlying Bid price Scenario assumptions for GB, though reflect the smaller number of generators. Scottish Bid prices are assumed to be positive at all times (assumes reasonable market behaviour), but can range from £0/MWh to the Scenario GB Bid price. The mean Scottish summer bid prices by scenario range from £11.40/MWh to £19.20/MWh. The mean Scottish winter bid prices range from £13.20/MWh to £23.40/MWh.

We further assume that a majority of the replacement energy (75%) can be sourced in the forward market, whilst the remainder (25%) is sourced in the BM due to inherent uncertainties in generator output, especially wind. Therefore, the replacement energy price also varies from scenario to scenario, and is itself probabilistic.

Results of Cheviot Constraint Cost Forecast

The table below summarises the forecast constraint costs across the Cheviot boundary:

Summary of Forecast Constraint Costs Across Cheviot Boundary (£m)

Forecast Cheviot Constraint Costs (Deterministic & Probabilistic)

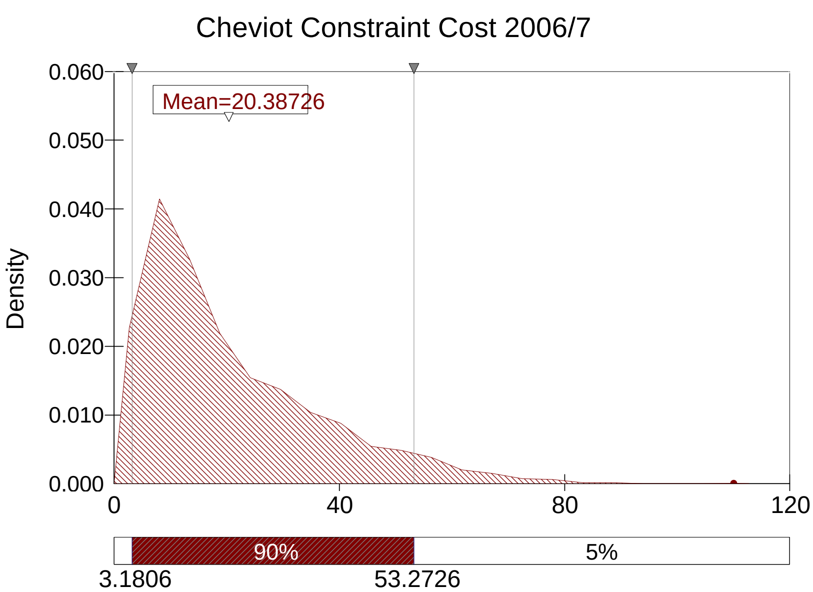
2006/07	*Scenario 1*	*Scenario 2*	*Scenario 3*	*Scenario 4*	*Scenario 5*	*Scenario 6*	*Scenario 7*	*Mean*
Scenario Probability	**5%**	**20%**	**25%**	**15%**	**20%**	**10%**	**5%**	
(a) Unconstrained Transfer (TWh)								
Summer - intact	0.74	0.71	1.19	1.29	1.29	1.17	1.17	**1.17**
Summer - outage	0.57	0.54	0.91	0.98	0.98	0.89	0.89	**0.89**
Winter	5.30	4.10	4.16	6.47	5.39	4.88	5.92	**4.88**
Latest Simulation	**6.61**	**5.35**	**6.26**	**8.74**	**7.66**	**6.93**	**7.98**	**6.93**
Mean Annual	6.61	5.35	6.26	8.74	7.66	6.93	7.98	6.92
(b) Constraints Volume (TWh)								
Summer - intact	0.00	0.00	0.00	0.00	0.00	0.00	0.00	**0.00**
Summer - outage	0.13	0.17	0.10	0.23	0.23	0.23	0.23	**0.17**
Winter	0.28	0.06	0.06	0.63	0.14	0.13	0.41	**0.14**
Latest Simulation	**0.40**	**0.23**	**0.16**	**0.86**	**0.37**	**0.36**	**0.64**	**0.37**
Mean Annual	0.50	0.30	0.24	0.92	0.53	0.52	0.74	0.48
(c) Constraints Cost								
Summer - intact	£0.0m	£0.0m	£0.0m	£0.0m	£0.0m	£0.0m	£0.0m	**£0.0m**
Summer - outage	£3.0m	£4.5m	£3.5m	£7.5m	£9.3m	£7.7m	£7.7m	**£7.5m**
Winter	£9.0m	£2.4m	£3.1m	£29.9m	£8.2m	£6.7m	£20.9m	**£9.0m**
Latest Simulation	**£12.0m**	**£6.9m**	**£6.5m**	**£37.3m**	**£17.4m**	**£14.4m**	**£28.6m**	**£14.4m**
Mean Annual	£15.0m	£9.5m	£10.4m	£40.0m	£26.3m	£22.2m	£33.1m	£20.4m
Std Dev Annual	£8.4m	£5.6m	£7.4m	£16.2m	£14.2m	£12.2m	£16.6m	£15.9m
					Mean Annual sumproduct check			**£20.4m**

N.B. Figures in blue represent the results of the most likely simulation result, figures in grey represent the mean of all simulations.

It can be seen that:

- The Mean Annual constraint volume varies from 0.24TWh to 0.92TWh with a weighted mean of 0.48TWh.
- The mean constraint cost is £20.4m, and varies from scenario to scenario due to different generation patterns and forward prices. The range is from £9.5m in Scenario 2 to £40.0m in Scenario 4.

The graph below shows the distribution of forecast constraint costs across the Cheviot boundary. The forecast constraint cost is highly uncertain and ranges from £0.1m to £112m. A more representative P90 range is from £3.1m to £53.3m.



Constraint Costs within Scotland

This year, we have experienced a number of constraints within both the SSE and SP 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.

Throughout winter 2005/6 to date, we have experienced conditions of low generation across the North of Scotland. The transmission network requires a modest level of local generation to secure demand across the whole of the North of Scotland throughout winter weekdays against double-circuit faults.[7] This constraint was acknowledged before BETTA Go-Live but, given historic trends, it was considered a low probability event that all the local generation would not to run for prolonged winter periods. Including the costs of this winter constraint, we project the costs of within-Scotland constraints to total £32m[8] for 2005/6.

For 2006/7, we forecast a similar total of constraint costs. The pattern of constraints is expected to adjust slightly. The commissioning of many windfarms, located across the Scottish systems, is expected to increase the pressure on export constraints, but on occasion they will relieve import constraints. Our forecast of the winter North-of-Scotland import constraint discussed above varies by scenario. For most scenarios, including those where gas prices are high, we assume that the local generation repeats its behaviour of this winter, and does not run, causing similar levels of cost as this winter. In remaining scenarios, this North-of-Scotland generation does run, and causes the high Cheviot export costs seen above.

Overall, we forecast the cumulative effect of these differing cost risks across scenarios is such that our forecast of within-Scotland constraint costs for 2006/7 is £31m.

Forecast within-Scotland Constraints (£m)

	2005/06	2006/07	
SSE Network	27	25	A variety of import and export constraints, under both intact network and outage conditions
SP Network	5	6	A variety of import and export constraints, mainly under outage conditions
Total	32	31	

Constraint Costs in England and Wales

The volatility of flows across the Anglo-French interconnector is a major factor influencing constraint costs in England & Wales. Based on detailed weekly system studies and market/generation intelligence, we estimate constraint costs in England & Wales to be £18m. The table below summarises the forecast constraint costs by major system area/boundary and by scenario.

7 Because the demand at risk exceeds 1500MW, the SQSS requires us to secure to double-circuit fault under all weather conditions.

8 This cost is here quoted on a gross basis, as this is the usual approach adopted for reporting constraint costs within-year. However, this cost may be subject to an Income Adjusting Event for this year, but we will raise the IAE on a net basis, namely accounting for the interaction with other balancing cost components.

Forecast E&W Constraints (£m)				2006/07 Scenarios							
Area/Boundary	2003/04	2004/05	2005/06	1	2	3	4	5	6	7	Mean
North	4	5	8	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5
South	24	11	4.5	10.5	6.5	6.5	10.5	6.5	6.5	6.5	7.3
Flow South	4	2	1.5	3	2	2	3	2	2	2	2.2
Total	32	18	14	22	17	17	22	17	17	17	18

The return of E&W constraint costs from a historic low of £12m in 2005/06, to the £18m level as in 2004/5 is primarily caused by the increase in transmission outages. 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 2006/7, 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.

Summary of Forecast GB Constraint Costs for 2006/07 (£m)

	2005/06	2006/7 Scenarios							Mean
		1	2	3	4	5	6	7	
England & Wales	13.8	22.0	17.0	17.0	22.0	17.0	17.0	17.0	18.0
Cheviot Boundary	14.1	15.0	9.5	10.4	40.0	26.3	22.2	33.1	20.4
Within Scotland	32	15.0	32.0	35.0	15.0	35.0	41.0	35.0	31.0
GB Total	59.9	52.0	58.5	62.4	77.0	78.3	80.2	85.1	69.4

In summary, we forecast a mean GB constraint cost of £69.4m with a range of £52m in Scenario 1 to £85m in Scenario 7. This is based on the mean forecast costs of Cheviot boundary and within-Scotland constraints for each scenario. On a probabilistic distribution basis, the GB constraint cost has a much wider range, which contributes to the forecast GB IBC distribution as shown in section 2.10.

Constraint costs in Scotland and across the Cheviot boundary remain particularly uncertain, and we have based our forecasts on historic experience, as demonstrated to date under BETTA. Whereas we have 12 years of experience in managing constraint costs in England & Wales, including 5 years under NETA, we have less than one year of experience and data in Scottish constraint management. In addition, a number of effective constraint management tools and controls, used to manage constraint costs in England and Wales, are not be available in Scotland, given the separate transmission ownership.

2.8 Transmission Losses Forecast

Methodology

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 (assumed for the purposes of this forecast to be £29/MWh, as in 2005/06).

$$TLA_{fcst} = \{ TL_{fcst} - TLT \} \times TLRP$$

Base Data

The base period is 2004/05, in which England & Wales losses totalled 4.453TWh and Scottish losses 1.122TWh, giving a GB total of 5.575TWh. The Scottish losses in 2004/05 were in fact extrapolated from 2003/04 data, as supplied by Scottish Power (0.664TWh) and S&SE (0.417TWh), a total of 1.081TWh.

Forecast

The table below shows

- actuals for 2004/05, with sub-totals for E&W and Scotland;
- a projection of GB losses for 2005/06;
- our mean forecast GB losses for 2006/07.

Transmission Losses (TWh)

	2004/05 outturn	**2005/06 projection**	**2006/07 mean forecast**
Scheme Type	*Gross losses*	*Net losses*	*Net losses*
England & Wales (TWh)	4.453	n/a	n/a
Scotland (TWh)	1.122	n/a	n/a
GB (TWh)	**5.575**	**5.659**	**5.82**
TLRP (£/MWh)	21	29	29 (assumed)
TL target (TWh)	n/a	5.79	5.82 (assumed)

The mean forecast GB TL for 2006/07 is 0.16TWh (2.8%) higher than our projection for 2005/06. This is due to the forecast 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 2006/07 is zero.

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

- Scottish generation

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

Across scenarios, forecast TL ranges from 5.74 to 5.93 TWh, with a mean of 5.82TWh. This gives forecast TLA ranging from –£2.4m to +£3.1m, 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 (£4.35m).

2.9 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 profile and risk management policy.

Forecast by Scenario
The table below summarises the forecast costs of IBMC+Trade by scenario.

Summary of Forecast Scenario IBMC+Trade Costs (Excluding Constraints) (£m)

	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5	Scenario 6	Scenario 7	Mean
NIA	-16.7	-15.8	23.7	51.4	24.5	-22.2	24.2	13.5
BMC'	43.8	48.8	96.3	124.6	100.3	60.5	130.5	87.3
Trade'	9.7	13.4	30.1	36.4	34.6	22.7	41.9	27.4
IBMC'	60.5	64.6	72.5	73.1	75.9	82.7	106.4	73.8
IBMC'+Trade'	70.1	78.1	102.7	109.5	110.5	105.3	148.3	101.3

As mentioned above, NIA, BMC' and Trade' directly interact with each other and are quite volatile from scenario to scenario. For example, NIA varies from -£16m in scenarios 1 and 2 to +£51m in scenario 4; 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.

The mean forecast cost of IBMC'+Trade' (ie excluding constraints) is £101.3m, with a range of £70m in scenario 1 to £148m in scenario 7.

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 low fuel costs and thus BM prices, and due to an assumed high level of free headroom. Similarly, high forward and BM prices in scenario 7 increase the cost of trades and margin actions, because low free headroom and plant margin require a high level of system actions for margin purposes. Therefore, the cost of IBMC'+Trade' in this scenario is the highest at £148m.

2.10 Total IBC Forecast and Distribution

Our total forecast of IBC, aggregating the categories discussed in sections B5 to B9, is shown in the table below:

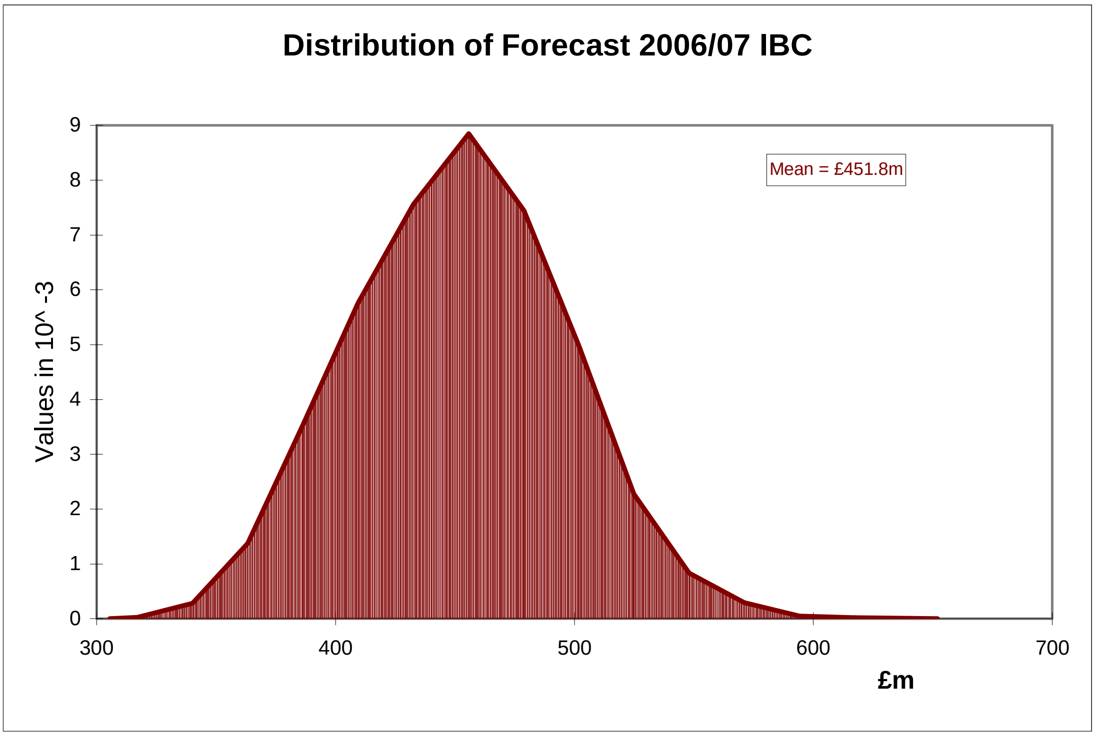
Summary of Forecast Scenario Costs for 2006/07 (£m)

	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5	Scenario 6	Scenario 7	Mean*
	5%	*20%*	*25%*	*15%*	*20%*	*10%*	*5%*	
IBMC+Trading less Constraints	**70.1**	**78.1**	**102.7**	**109.5**	**110.5**	**105.3**	**148.3**	**101.3**
AS less Constraints	**266.4**	**271.8**	**280.4**	**283.2**	**289.7**	**280.8**	**289.7**	**280.8**
Transmission Losses	**-1.9**	**-1.6**	**0.6**	**-1.3**	**2.1**	**1.3**	**-1.3**	**0.0**
Constraints	**52.0**	**58.5**	**62.4**	**77.0**	**78.3**	**80.2**	**85.1**	**69.4**
IBC	**386.6**	**406.8**	**446.1**	**468.3**	**480.6**	**467.6**	**521.8**	**451.4**

Notes: Scenario probability weighted average

It can be seen that IBC varies from £386m in scenario 1 to £522m in scenario 7. The probability-weighted mean forecast is £451.4m.

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.



The distribution is slightly skewed, and shows a significant range from a 5th percentile at £379m to a 95th percentile at £524m. The standard deviation of our forecast is £44m.

2.11 Comparison with Previous Years

Summary of Forecast Scenario Costs for 2006/07 (£m)

	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5	Scenario 6	Scenario 7	Mean*
	5%	*20%*	*25%*	*15%*	*20%*	*10%*	*5%*	
IBMC+Trading less Constraints	**70.1**	**78.1**	**102.7**	**109.5**	**110.5**	**105.3**	**148.3**	**101.3**
AS less Constraints	**266.4**	**271.8**	**280.4**	**283.2**	**289.7**	**280.8**	**289.7**	**280.8**
Transmission Losses	**0.8**	**-2.4**	**-1.3**	**3.1**	**1.1**	**0.0**	**1.6**	**0.0**
Constraints	**52.0**	**58.5**	**62.4**	**77.0**	**78.3**	**80.2**	**85.1**	**69.4**
IBC	**389.3**	**406.0**	**444.2**	**472.8**	**479.6**	**466.3**	**524.7**	**451.4**

Notes: Scenario probability weighted average

The table below compares the forecast IBC for 2006/07 with historical outturn IBC in E&W since NETA Go-Live. For consistency, the outturns are shown in the same format as the forecast.[9]

Of course, costs for previous years are on an England & Wales basis, whereas our projection for 2005/6 and forecast for 2006/7 are on a Great Britain basis. The historic years also treated TL gross, whereas the forecast years have TL net.

2.12 Consideration of Forecast

The mean forecast of £451m for 2006/7 is £56m above our projection of £395m for 2005/6. As discussed in the previous sections, there are many factors driving this increase. For discussion purposes, we have grouped the major changes into the following categories

- Volume effects, mainly market externalities which increase the volume of balancing actions we require to maintain system security standards; (£10m)
- Price effects, directly ascribed to the rise in power prices; (£18m)
- Price effects, linked to the evolution of competitive pressures and pricing for individual balancing services; (£11m)
- Cost effects, on components which are currently subject to Income Adjusting Events. (£17m)

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 £10m

- The rise of £4m in the costs of England & Wales constraints, as discussed above, is due to the growing level of transmission outages required to refurbish parts of the NGC system. This is thus a volume effect, where the cost increase is due to a greater volume of balancing services required to be procured.

- The costs of Reserve, also known as Margin, remain large and variable within both Ancillary and BM+Trading. Our detailed analysis of these cost terms shows an increase from this year to next for Standing Reserve within Ancillary and

[9] Constraint costs cannot be exactly calculated for a historic year's outturn. However, we can estimate the cost for the purpose of analysing balancing costs.

consequent saving within BM+Trading, giving a net effect of £2m, which is a volume effect.

- Our forecast of the net cost of Transmission Losses, namely the TLA term, shows an increase of £4m. This can be entirely explained by the increase in Scottish wind generation.

Price Effects, due to Gas and Power prices £18m

- The price of Reactive within Ancillary is derived from our forecasts of power prices by scenario. The entire increase of £15m in Reactive costs year-on-year is explained by the higher average level of forward prices for next year.

- The price we pay for Margin actions, either within the BM or in forward Trades for Margin, is related to power prices. Providers charge a premium for actions which deliver Margin (or Reserve), and we have observed across the last two years that the average price of our Margin actions averages approximately double the current power price. This effect alone, applying the Margin price rise pro rata to the power price rise for next year, across our volume of Margin actions (which is similar year-on-year), shows a £5m increase in costs.

- 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 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 -£2m reduction from this year to next.

Price Effects, due to evolution of Balancing Services £11m

- We forecast greater price rises across Reserve procurement within Ancillary and Margin actions within BM+Trading, than can be explained in terms of power prices alone. We forecast a further £11m increase in the cost of these services. In particular, we have already seen the price increases for the tendered prices submitted for Standing Reserve.

Costs subject to Income Adjusting Events in 2005/06 £17m

Our exposure to the following costs is subject to an agreed level within BSIS 2005/06. Costs outside this level may be subject to an IAE. For the BSIS 2006/07 a central forecast for these costs has been produced and, as discussed above, assumes no specific IAE mechanism.

- As discussed within section 2.7, we forecast the cost of Cheviot Constraints to increase by £6m year-on-year. This is due to the increased volume of Wind generation in Scotland.

- As discussed within section 2.6, we believe that the on-cost of CAP047 across its first full year of implementation will be £21m. This is £11m above the equivalent projection of £10m for this year (all figures rounded to the nearest £1m).

Overall Consideration

It can be seen that the majority of forecast cost increases across balancing services are linked to:

- the change in power prices (such as Reactive);
- the implementation of new mechanisms (such as CAP047);
- Scottish constraint costs that were, pre-BETTA, internalised within SP and SSE; or
- are the result of clear pricing signals within areas of competitive service procurement, such as Margin / Reserve.

In addition, a smaller part derives from increases in the volume of actions we require to take to secure the system, either as a result of:

- Increased constraint expenditure linked to the rise in CAPEX for transmission equipment refurbishment and replacement; or.
- Reduction in free headroom delivered from the market that results in increased procurement of Margin by National Grid

Balancing Services are increasingly procured on a transparent, open and competitive basis; thus the forecast cost increases represent the trends and signals that we observe both within formal tender/procurement mechanisms and within the Balancing mechanism.

2.13 Conclusion

There continue to be significant uncertainties and challenges in forecasting IBC for 2006/07. The revision of our own forecast for 2006/07 and for the current year, 2005/06 clearly illustrates the continued presence of uncertainty and the challenge of forecasting IBC. The further work undertaken and the revised forecast has allowed us to reflect our most up-to-date information, understanding and operational experience of balancing the system, particularly with respect to winter operation under both BETTA and a tighter gas market.

We believe that the bottom-up, scenario based extrapolation approach we have adopted is a robust and sensible method. It allows us to identify many underlying cost drivers whilst at the same time enables us to forecast IBC as a whole, reflecting through the underlying uncertainties within the many drivers and in the interaction between different drivers.

We have identified a number of cost drivers for BSIS 2006/07. These include rising forward prices, pricing pressures in Ancillary markets and the continuing costs of CAP047, and the continued revealing of the true extent of constraint costs in Scotland. In addition, our recent work has allowed us to better quantify the range of possible forecast scenarios, with particular respect to winter operation, gas market interaction, forward prices and constraints. We believe our forecasts are robust and are, in many cases, based on the trends and pricing signals given to National Grid by open and competitive market mechanisms such as the Balancing Mechanism, Forward Markets, CAP047 and competitive tenders, in particular those for Standing Reserve, Reactive power and Firm Frequency Response. With regard to the range of values used for forecast scenario drivers, we have continued to ensure these closely reflect the observed ranges of historic and current data, accounting for known variation, and where possible we have also used signals seen in the prompt and forward markets.

Where greater uncertainty exists we have, where appropriate, developed forecast models to reduce uncertainty and looked for historic examples to understand possible behaviours. Through our recent work we believe we have increased the accuracy of our forecast in the key areas of winter operation under both BETTA and a tighter gas market. Overall we believe we have taken a balanced view, based on the most up-to-date information, reflecting both the opportunities and risks that these challenges present to the ongoing development of the operation of the system and management of balancing costs.