

National Grid's Initial Forecast of Incentivised Balancing Costs for Great Britain in 2009/10

1. Summary

This Appendix presents the detail behind our initial forecast for National Grid's 2009/10 balancing costs.

The forecast is split into its component parts. Where possible, areas with a significant cost risk have a range included to indicate the level of uncertainty within the forecast. The detailed information is focused on the areas where there are significant changes in costs from our 2008/9 forecast.

During 2008/9 we have seen dramatic, and unprecedented, rises in the costs of system balancing. These rises have been linked to, amongst other things:

- Wholesale price increases
- Introduction of the Large Combustion Plant Directive (LCPD)
- A reduction in "free" headroom leading to increased Margin creation activities

These drivers have also pushed up the costs of constraint management by increasing the spread in price between Bids and replacement Offers, which have often required the synchronisation of additional units.

Underlying the forecast for 2009/10 is the acknowledgement that the introduction of LCPD and reduction in free headroom represent a change in market operation that is highly unlikely to fully reverse itself in the next year.

In addition we anticipate that

- Constraint costs will be higher in 2009/10 by some £114m as a result of the anticipated outage programme and significant increase in wind generation within Scotland
- STOR contract costs will continue to follow the increases of previous years and so raise by £19m
- Reactive costs increase by £20m from the 2008/09 forecast based on power price and RPI increases to the default prices and the anticipated pattern of generation and demand

Further we have estimated that the introduction of "Use It or Lose It" arrangements over the France – UK Interconnector will result in an increase to costs of £21m due to the loss of forward trading opportunity.

Conversely, we forecast that response costs and the costs of creating operating reserve will reduce with improved availability of demand side providers in 2009/10.

A number of these drivers are outside the direct control of the System Operator. Reductions that the System Operator can bring about via economic and efficient operation are already reflected in the forecast.

A further change within the 2009/10 forecast is the introduction of a new Net Imbalance Adjustment (New NIA) to replace the existing NIA term. This is designed to more accurately represent the fluctuations in Incentivised Balancing Costs as a result of wholesale price and market length changes.

1.1 Changes in Forecast Assumptions

There are a number of risks associated with fixing assumptions. We expect some of these drivers to change prior to final scheme proposals in late February. In particular:

- network outages will become more certain as works programmes are finalised early in the new year;
- power price - we will use the most recent further information on the wholesale power price for our final forecast;
- we will have a clearer view of STOR costs for 09/10 following the January tender round;
- we will have further data on reserve and response costs for the current winter.

Forecast outturn 2008/09 costs form part of the basis of the 2009/10 forecast in that the historic out-turn costs since April 2003 is used to forecast the future and 2008/09 forms a part of that history. Bearing that in mind, the step changes in the market, LCPD implementation and increased wind generation during 2008/09, may have a greater impact on 2009/10 than currently forecast as a result of the dilution of 2008/09 from extrapolating/averaging 5 years of historic data.

The market has been more balanced during 2008/09, showing a step change in Net Energy and Margin. We believe this may be due to generators and suppliers becoming more comfortable with the cost exposures associated with balancing their own positions.

Use It Or Lose It (UIOLI) is a new component for 2009/10 which will also see a significant increase in BSIS costs. This is due to new legislation which has reduced National Grid's access to capacity on the GB interconnector.

2008/09 saw a significant increase in outage volume and costs due to connection of new generation and system re-enforcement. We expect further increases in constraints costs in 2009/10 due to connection of new generation and further system re-enforcement.

1.2 Forecast Volatility

The forecast is not a single number. We discuss the likely range of balancing costs within this document and we would encourage participants to also take into account this range when considering our scheme proposals. To illustrate the range, we have included a number of scenarios and we would welcome feedback on our assumptions within these.

This forecast represents our best view of next year's incentive balancing costs. There are many assumptions required to build such a forecast and these assumptions can and will change prior to the scheme being implemented. The drivers will continue to change costs through the scheme year. We have developed a forecast range to identify where these changes in assumptions will have an impact on the forecast. Therefore when considering the forecast, the range of potential costs and the corresponding risks need to be considered in conjunction with the central forecast.

2. Introduction and Assumptions

This appendix presents our forecast of balancing costs for 2009/10.

Section 3 outlines the forecast method and considers the drivers of incentivised costs. Section 4 presents the overall forecast and discusses each forecast element.

In preparing this forecast, we have had to make three basic assumptions:

- In line with the scheme proposals put forward elsewhere in this document, our forecast assumes that NGET's role and responsibilities to balance the system remains the same for 2009/10 as in 2008/9;
- The impacts of BSC modifications or CUSC amendments to be introduced after 1 October 2008 have not been considered;
- In particular, for this forecast we have not assumed a material change to system operation, or the drivers thereof, due to changes to Cashout or Transmission Access arrangements.

3. Construction of Forecast

The aim of this forecast is to predict the likely range and central figure for balancing costs incurred in 2009/10. Incentivised balancing costs (IBC) are defined in NGET's transmission licence^a.

IBC covers National Grid's External System Operator costs, i.e. the net costs incurred on procuring services to balance the GB system. The majority of our forecast is undertaken by extrapolation, i.e. forecasting the trend for next year based on current and historic trends. We also adjust inputs based on known or anticipated changes which may impact that component. This is the case for all areas except for:

- Transmission Network constraints, as these are dependent on the outages that will be undertaken during the year in question, and also dependent on forecast generation output and prices;
- Our forecast cost increase due to the additional connection of wind generation is an extrapolation of existing experience of wind generation combined with anticipated new connections, notably behind constraint boundaries.

For the 2009/10 forecast, we have considered the following key drivers to have the greatest effect on overall balancing cost:

- Wholesale electricity prices
- Balancing Mechanism Prices
- Scottish generation output levels
 - Transfers to / from Scotland
- Volume of wind generation
- Changes to EU legislation regarding Interconnector transfers
- Level of market length

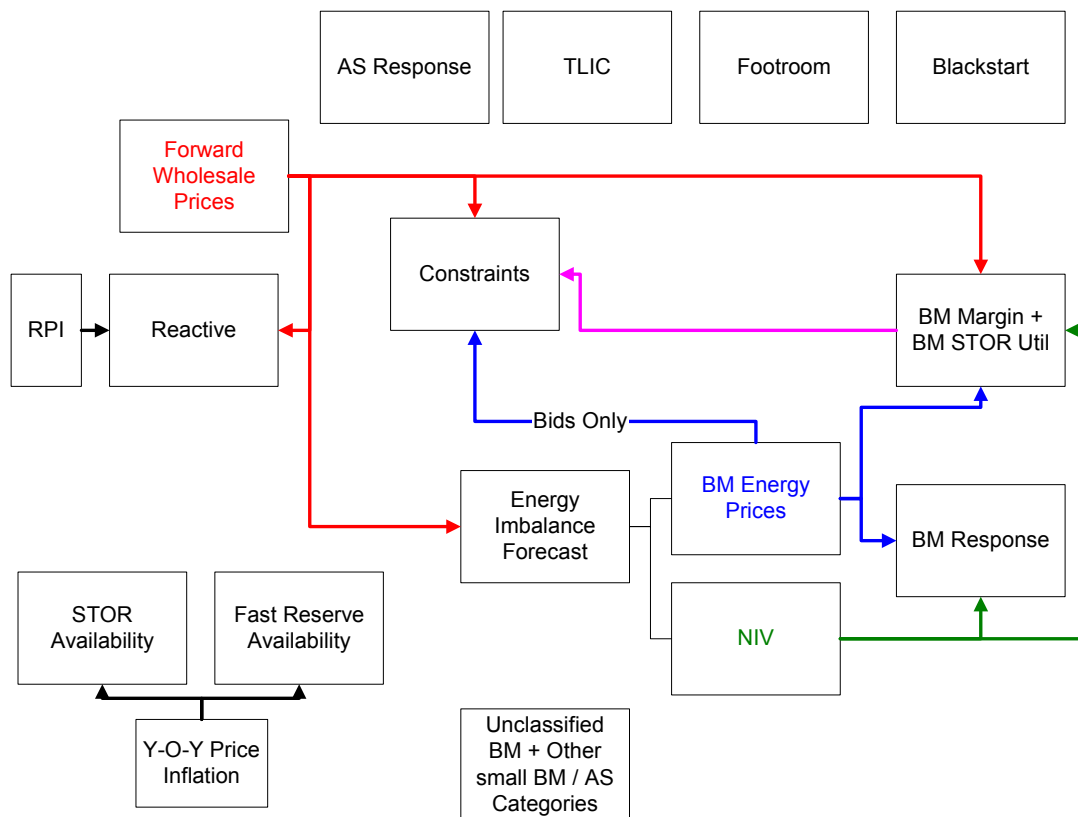
^a For a full explanation of IBC, BSUoS please see our BSIS Seminar presentation of 10th January 2007, which formed part of last year's consultation process. This is available in the Ops Forum area of our industry information website here:
http://www.nationalgrid.com/NR/rdonlyres/9065C6F7-BDEE-419E-8033-9D4BDE01442F/14305/BSIS_Seminar10_1_07.pdf

- Price trends in the procurement of balancing services
 - Reserve
 - Frequency Response
 - Reactive
- GB Transmission System Outage programme
- Generator availability and operating regimes

There are many other cost drivers that influence GB IBC but are not explicitly included in this forecast 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. The impact of LCPD is also now included within the forecast components affected, notably Margin, based on the experiences of 2008/9.

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.

Specifically, our forecasting technique consists of a number of separate models many of which share key inputs as shown in the diagram below:



The historical trend and forecast future performance of the above key cost drivers are described below.

3.1 Balancing Cost Drivers

3.1.1 Electricity Forward Price

The electricity forward price impacts on IBC in several ways, including the costs of our pre-Gate trades and BM actions, the volume and direction of flows across the Anglo-French interconnector and the price of reactive power.

Average power prices have risen dramatically since March 2008 when the APX Market Index Price averaged £55/MWh. Since then prices have increased to a peak, so far, of £100/MWh in September before falling slightly in October. Current forward prices^b suggest an average baseload price of £72.50/MWh for the remainder of BSIS Year 2008/9.

The following table outlines our power price assumptions for the initial forecast for the 2009/10 BSIS Year. This will be updated before the final scheme proposals in February.

	UK	
	BSLD	PKS
	£/MWh	£/MWh
Q209	60.60	73.10
Q309	60.00	72.40
Q409	64.60	76.00
Q110	67.80	85.30

(Prices from Argus on 17-Oct-08)

This equates to an average baseload price of £60.30/MWh in summer and £66.20/MWh in winter, with average peak prices of £72.75 in summer and £80.65 in winter.

The 2009/10 initial forecast has an underlying forward price curve for wholesale energy prices which is 14% higher than the 2008/09 initial forecast, but lower than out-turn prices to date for 2008/09. This forward curve directly feeds into some of the components, but others have no direct link to the level of the forward curve. Our assumptions of forward prices for 2009/10 are based on the prices quoted by Argus on the 17th October and will be updated when the final forecast is run.

3.1.2 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 closure.

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

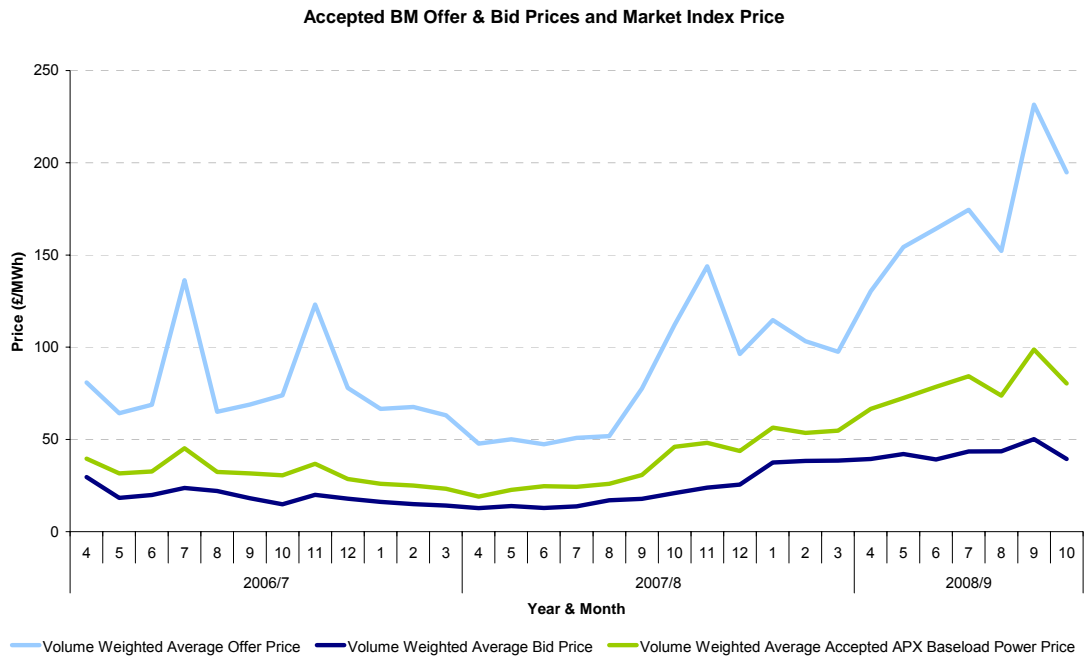
- the Bid and Offer prices submitted (which reflects the degree of competition in the BM as well as generators' behaviour); and
- degree of competition for locational services; and
- the volume of actions taken to balance the system.

The BM Bid market is competitive, with a relatively stable average price, with a large volume of bids accepted principally for energy balancing purposes. 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

^b Quote date 10th November 2008

bids and is more closely associated with balancing actions taken to create Operating Reserve or to resolve system constraints and is therefore more volatile than the more 'liquid' average bid price.

The graph below shows the volume weighted average accepted BM Offer and Bid prices) from 2006 to October 2008 against the volume weighted average accepted APX baseload power price.



The graph shows a reasonable correlation between power prices and both Bid and Offer prices, although this is more pronounced in the Offers than in the Bids. This widens the spread resulting in a higher overall cost for any system actions.

3.1.3 Scottish Generation Output Levels

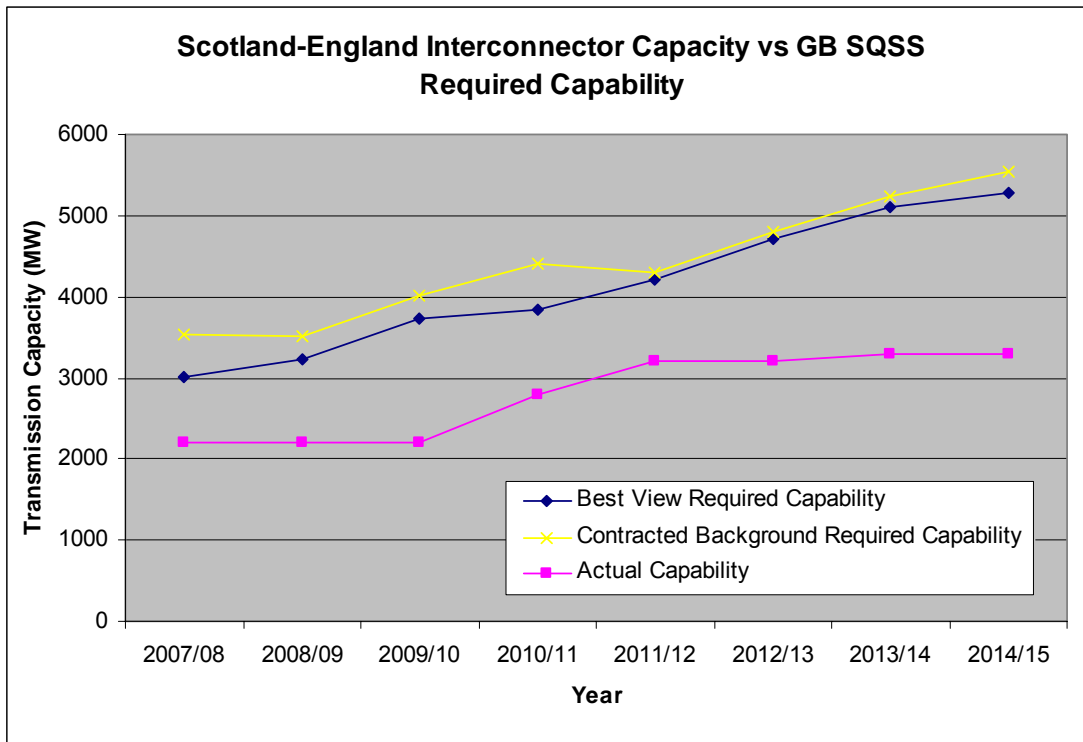
With the current Scottish demand levels, Scottish generation profile and Scottish transmission topology, there are a number of intact and outage-related transmission constraints. These can vary significantly over the year, with the Scottish system being both an import and export constrained group within year.

With a relatively predictable demand profile and the majority of significant system outages being known at the year ahead timescale (finalised in January 2009 for 2009/10), the greatest risk results mainly from the generation profile and price, although delays to outages can also extend the period over which these risks are present.

3.1.4 Transfers to and from Scotland

The Scotland to England flow boundary, commonly known as the 'Cheviot' boundary is derogated against the Security and Quality of Supply Standards (SQSS) because the boundary has insufficient capacity to meet SQSS standards. There are a number of planned system developments to increase the Cheviot boundary capacity. These works are planned over the next four years. These construction works require long outages that reduce the transfer capacity, and therefore increase constraints in the short term.

The following graph shows the required intact system capability of the Scotland-England boundary based on the Contracted and a 'Best View' generation background plotted against the boundary capability following sanctioned network reinforcements. This 'Best view' is lower than the Seven Year Statement (SYS) 'contracted level', being based on a wider set of data. We believe this 'best view' is consistent with BWEA expectations for future wind generation growth in Scotland. This means that the best view required capability is lower than the capability that would be obtained by simply summing the TEC of all contracted generation.

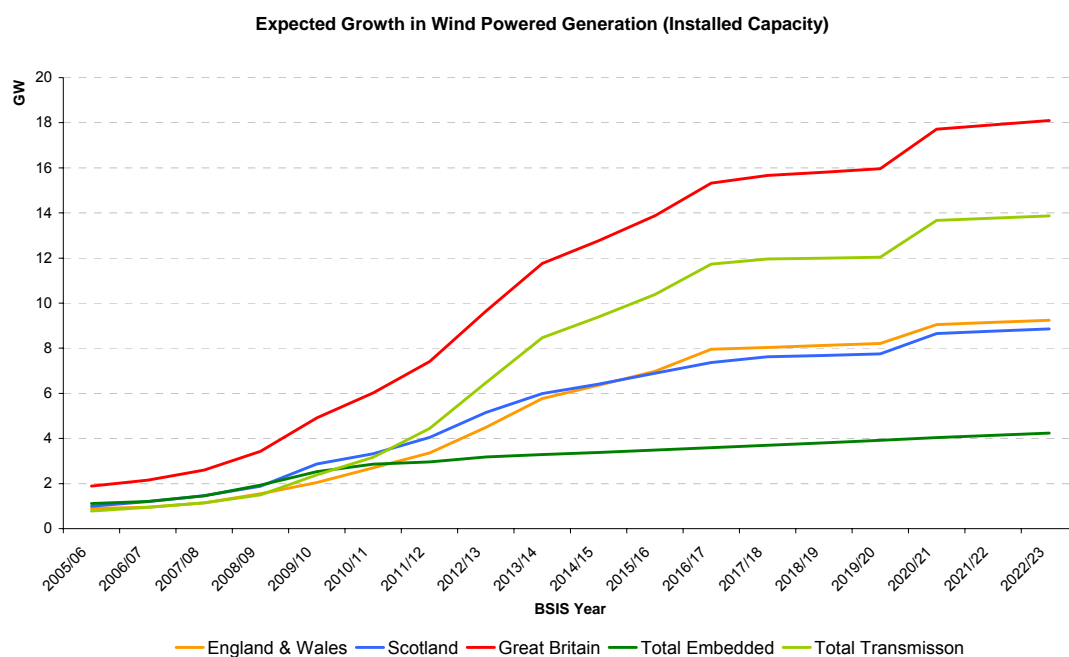


As can be seen in the above graph, even for an intact system, there are transfer limitations where required capability exceeds actual capability. These limitations are significantly increased by taking system outages.

The actual capability is constrained by the post fault level. There are two double circuits carrying power across the Cheviot boundary. In the event of a fault on one double circuit, the other double circuit must be capable of instantaneously carrying the total power that was flowing across the two double circuits. Thus, while one circuit's capacity has increased following the first stage of reinforcement works during summer 2008, the capacity across the boundary will not increase until winter 2009 following initial reinforcement works on the other circuit.

3.1.5 Increase in the Volume of Wind Generation

The table below shows our projected growth of wind power based on Consents Received up to 2013 and beyond.



In forecasting the effect of increasing wind output on system operation, we can look to a number of sources:

- Our experience of current levels of wind generating in Great Britain;
- Forecasts of future wind output patterns based on known inputs such as weather variance and distribution of wind generation across GB;
- Where relevant, the experience of other systems across Europe and around the world.

Increased wind output and the corresponding greater generation intermittency will place greater balancing costs on both market participants and the SO. How this burden falls between the SO and the market will depend on the incentives (efficient avoidance of imbalance charges) to do so and the market's ability to forecast wind output and balance its own position.

Higher densities of wind generation, particularly in Scotland will lead to an increased volatility for forecasts of plant output at all lead times. This increased unpredictability of plant output, and hence power flows will impact on most of the activities the SO undertake to balance the system.

The two cost areas that will see the greatest immediate impact at the current relatively low levels of wind penetration are reserve and constraint management. The forecasts for these components include an estimate for any effects of increasing wind generation.

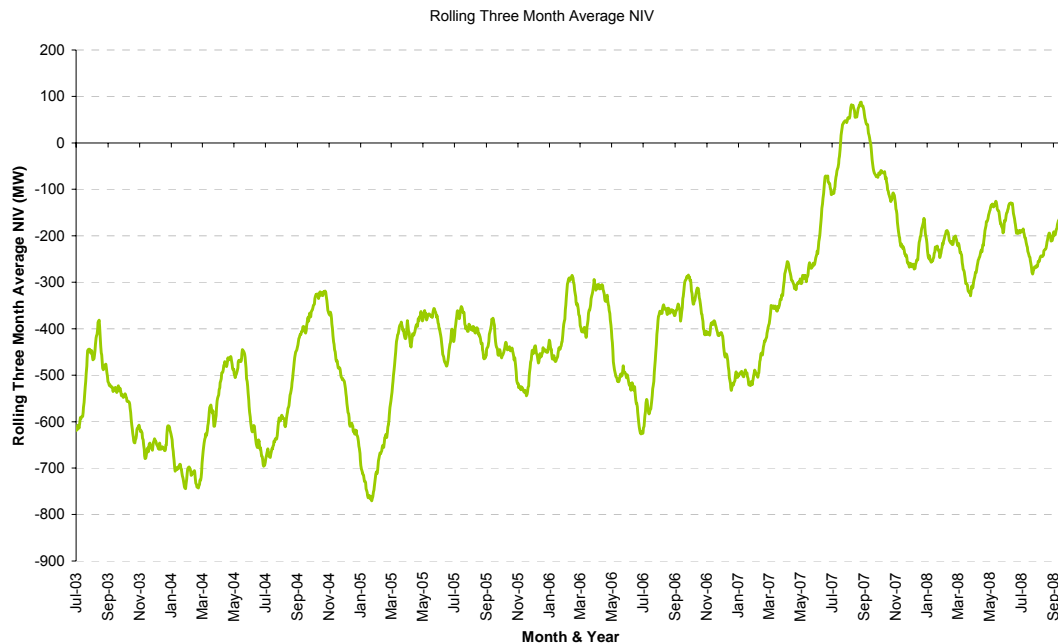
3.1.6 Market Length

Net Imbalance Volume, NIV, is defined in section T4.4.4 of the Balancing and Settlement Code (BSC). It 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 in the Balancing Mechanism and pre-Gate Closure.

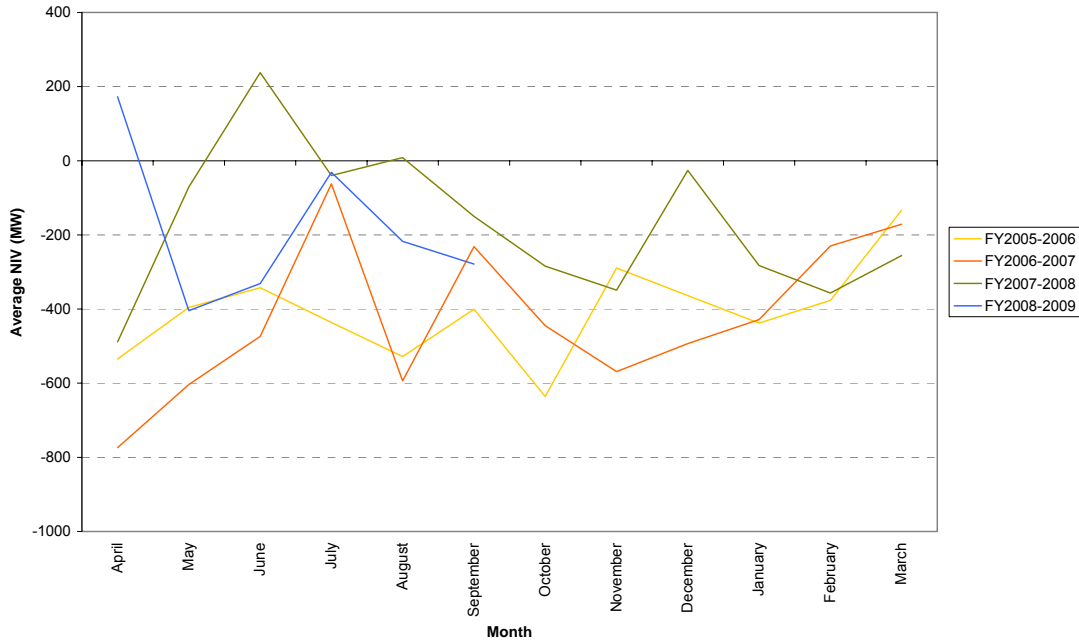
NIV directly determines the volume, and hence the costs, of Bids and Offers which we have to take to balance the market and hence meet out-turn demand. It also affects the amount of operating margin available to us from the market at Gate Closure because any headroom provided by a long market (negative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

Historically in the majority of Settlement Periods NIV has been negative, indicating a long market that we must resolve by taking Bids in the BM.

The graph below is a 3 month rolling average of NIV. As can be seen, average NIV has become slightly less negative (more balanced) over the last three financial years before settling in to a new plateau at around 200MW long since the autumn of 2007.



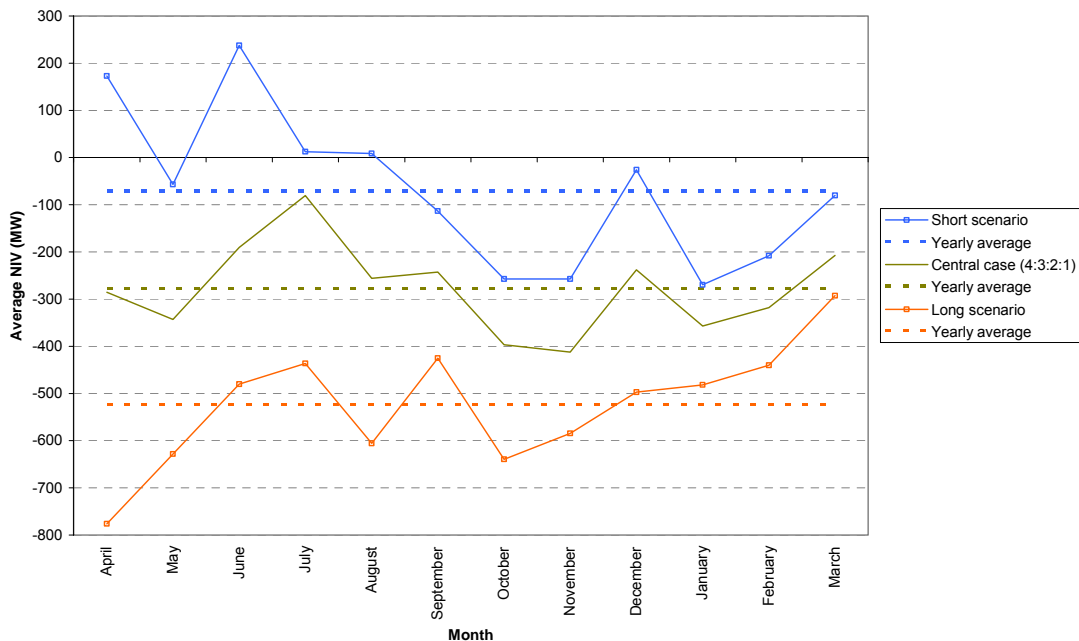
The seasonality of NIV can be seen from the following graph, which shows monthly average NIV for the last four BSIS years.



In our NIV forecast we have used three scenarios (short, central and long) in order to develop a range of possible outcomes for NIV.

The “short scenario” is derived by assuming that every EFA block in every month will be as short as the shortest (or least long) respective EFA block/month since BETTA go-live. Likewise, the “long scenario” assumes that every EFA block in every month will be as long as the longest since BETTA go-live. The “central scenario” is an average of the four years since BETTA go-live, weighted as 4:3:2:1 to 2008/9:2007/8:2007/6:2006/5. For example, for EFA block 1 in April, the shortest year since BETTA go-live is 2008/09, while the longest is 2006/07. Therefore the “short scenario” uses 2008/09 NIV data and the “long scenario” uses 2006/07 data for April EFA 1.

The graph below outlines our forecast views of NIV for next year on a month by month basis:



3.1.7 Price Trends

There are a number of balancing services that are influenced by certain market trends. Reactive power prices are affected by both volumes and prices where price is indexed to power price and RPI. Reserve and response costs are linked to market behaviour of providers and their strategies. There is significant risk on the costs of providing these services if market conditions change from those forecast e.g. winter colder than forecast, markets become shorter than assumed, gas price increases /decreases.

We have developed a range of costs to cover the potential variation in cost drivers.

3.1.8 Generator Availability and Operating Regime

As discussed later in section 6.4, 2008/09 has seen reduced nuclear availability and changes to operating regimes of LCPD plant. Both of these have had the effect of reducing the amount of margin inherent on the system, known as headroom. As a result of this decline, the volume of actions that National Grid has had to take to procure operating reserve has increased. Headroom in 2009/10 is assumed to follow a similar pattern to the previous four years, with a weighting of 10:6:6:3 for 2008/09:2007/08:2007/06:2006/05 to reflect the greater probability of the system being similar to the previous year rather than that of several years ago.

In terms of fuel mix, it is assumed that:

- Nuclear availability will improve from 2008/09;
- Coal plant with FGD will be operational and running as baseload;
- Gas will be the marginal fuel and therefore the marginal generation;
- Wind volume will increase, at a discounted rate against the consented connection plan;
- There will be a greater export volume to France based on the current forward curves. Forward prices are shown below, with a negative differential indicating an assumed flow to France.

Price differentials between GB and France derived from Argus, 17 October 2008

£/Mwh	UK BSLD	FRENCH BSLD	BSLD Differential	UK PEAK	FRENCH PEAK	PEAK Differential
APR	59.84	47.83	12.01	72.18	65.06	7.12
MAY	57.11	45.65	11.46	68.89	62.10	6.79
JUN	64.85	51.84	13.01	78.23	70.51	7.72
JUL	65.07	53.16	11.91	78.51	79.12	-0.61
AUG	57.25	46.77	10.48	69.08	69.61	-0.53
SEP	57.68	47.13	10.55	69.61	70.14	-0.53
OCT	51.09	57.79	-6.70	60.10	77.75	-17.65
NOV	64.01	72.40	-8.39	75.31	97.42	-22.11
DEC	75.64	85.56	-9.92	88.99	115.12	-26.13
JAN	70.90	78.34	-7.44	89.21	107.13	-17.92
FEB	65.51	72.38	-6.87	82.42	98.98	-16.56
MAR	70.19	77.56	-7.37	88.31	106.05	-17.74

Our assumptions on new plant commissioning directly affect the England & Wales constraint component, where our assumptions are:

- Newly fitted FGD plant will run hard, at the detriment of LCPD opted out plant which will look to conserve hours.
- Langage will be fully operational by April,

- Marchwood will be fully operational by the end of June,
- Immingham stage 2 by April 2009.

There is a significant risk that these dates may slip, as has been observed with commissioning of CCGT's in the past.

3.2 Net Imbalance Adjustment

According to National Grid's Electricity Transmission Licence, the incentivised cost of balancing services (IBC) is defined according to the following equation:

$$IBC = CSOBM + BSCC + TLIC + [\sum TQEI * NIRP] - RT - OM$$

where,

CSOBM is the sum of costs of bids and offers accepted in the balancing mechanism;

BSCC is the sum of the costs of contracts for the availability or use of balancing services, excluding costs within *CSOBM*;

TLIC is the net cost of transmission losses having taken into account the incentive to minimise the volume of transmission losses;

RT means the amount of any allowed income adjustments;

OM means an amount representing the revenue from the provision of balancing services to others; and

$[\sum TQEI * NIRP]$ is the so called Net Imbalance Adjustment (NIA), with:

TQEI is the total net imbalance volume as defined in the Balancing and Settlement Code (BSC)

NIRP is the net imbalance volume reference price, defined as

2.5 * *SPNIRP* on settlement periods when $TQEI < 0$

0.5 * *SPNIRP* on settlement periods when $TQEI > 0$

SPNIRP is the single price net imbalance volume reference price for

each settlement period, derived from the United Kingdom Power Exchange (UKPX) volume weighted reference price.

As it stands, NIA is a term designed to neutralise the impact of the volatility of market length (measured by *TQEI*) and power price (measured by *SPNIRP*) associated with the costs of resolving energy imbalance.

3.2.1 Designing a New NIA

Recent changes to market conditions, in particular the combination of low imbalance volumes and high power prices, highlighted the fact that NIA does not protect National Grid from exposures to changes in power prices in a near balanced market. National Grid consulted with the Industry over the summer on possible changes^c.

Following responses to the consultation document, a modified NIA is proposed, where the current and new formulae are as detailed below;

$$\text{Current NIA} = \sum[(\text{MLM} \times \text{market length} - \text{VO}) \times \text{power price}]$$

where

MLM is the Market Length Multiplier defined as

2.5 for settlement periods when the market length is short^d

0.5 on settlement periods when the market length is long^e

VO is the Volume Offset, calculated at 0

Power price is SPNIRP which is defined in the transmission licence

Market Length is TQEI which is defined in the transmission licence

$$\text{New NIA} = \sum[(\text{MLM} \times \text{market length} - \text{VO}) \times \text{power price}]$$

where

MLM is the Market Length Multiplier defined as

1.25 for settlement periods when the market length is short

0.90 on settlement periods when the market length is long

VO is the Volume Offset, calculated at 450

Power price is SPNIRP which is defined in the transmission licence

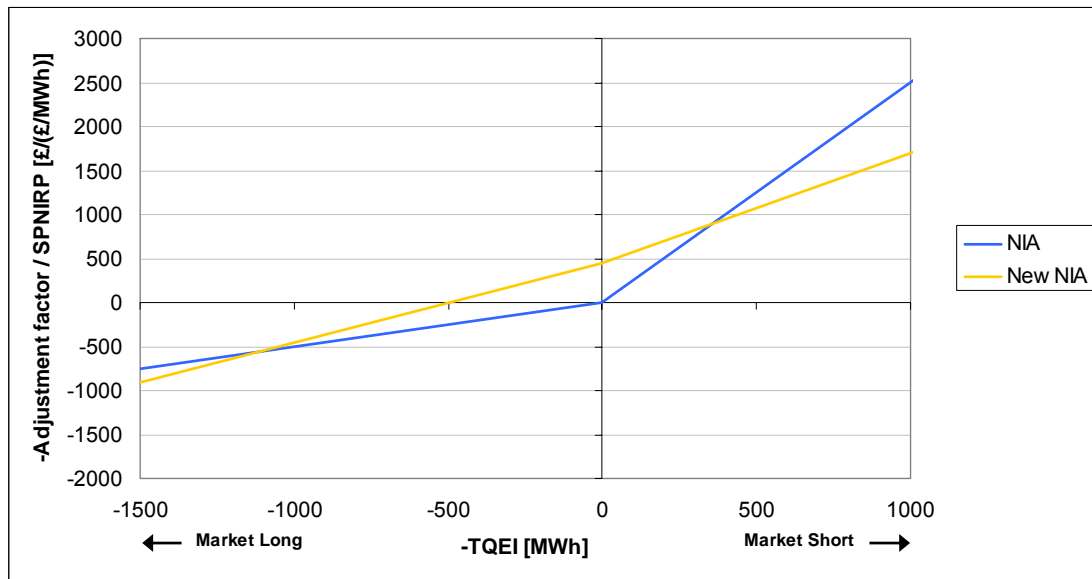
Market Length is TQEI which is defined in the transmission licence

^c http://www.nationalgrid.com/NR/ronlyres/E1C3C89D-1F71-467D-A052-C204B29C7F04/28024/Indexationconsultationdocument_posted.pdf

^d The market is short when TQEI is negative

^e The market is long when TQEI is positive

Graphically, the New Net Imbalance Adjustment Factor can be represented as follows:



Current NIA was designed to neutralise the impact of the volatility of market length (measured by TQEI) and power price (measured by SPNIRP) associated with the costs of resolving energy imbalance. By adding an offset to take account of costs incurred in a near balanced market, new NIA is designed to neutralise the impact of the volatility of market length and power price associated with the costs of resolving energy imbalance and procuring operating reserve.

4. Balancing Service Forecast Costs

Within this document there are a number of tables outlining our forecast costs for each component. The numbers are rounded to the nearest million. This can result in component numbers summing to different total values on occasions.

Methodology

Historical costs and volumes of Balancing Service contracts are set out in our Monthly Balancing Services Statements and also reported to Ofgem. Our forecast model follows a similar reporting methodology but with the addition the BM costs associated with the procurement of each service.

The derived BM cost of each service is developed using the following formula:

$$\text{Allocated cost of action} = \text{Volume} \times (\text{Price of action} - \text{Energy Reference Price}^f)$$

The Energy Reference Price (ERP) is the volume weighted average of the submitted bids or offers available to resolve NIV in that settlement period ignoring plant dynamics (i.e. $\text{ERP} = \text{Energy Imbalance Cost} / \text{NIV}$). This does not include non-BM standing reserve prices, trades, PGBTs or SO-SO trades.

A Monte-Carlo based approach has been used to combine a range of scenarios of price and volume in order to produce a probability distribution for each component of the model. These are presented with each component, together with the 10th and 90th percentile values.

Monte Carlo methods are a class of computational algorithms that rely on repeated random sampling to compute their results. The inputs for the Monte Carlo simulation are nine deterministic modelled scenarios using single-point estimates. Each scenario is assigned a probability and various combinations of each scenario are randomly sampled. Running this process 10,000 times produces the probability distributions shown in this report.

^f Energy Reference Price is calculated per settlement period.

4.1 Baseline Forecast Summary

Our central forecast for baseline Balancing Services costs is summarised in the table below. The table shows the latest forecast costs for 2008/09, and our forecast for 2009/10, comparing on a like for like basis, using the proposed New NIA.

All Categories £m	2008/09 Current Forecast Outturn with New NIA	2009/10 Initial Forecast with New NIA	Difference
Net Eng + Margin	-152	12	163
Net Energy	-569	-418	151
Energy Imbalance	-25	-16	9
New NIA	-544	-402	142
Margin	417	430	12
STOR	74	93	19
Operating Reserve	323	314	-9
BM Start-up	20	23	3
Constraints	194	307	114
CST - Cheviot	125	161	36
CST - Scot.Int	44	81	37
CST - Eng.Wales	24	65	41
Footroom	8	7	-1
Fast Reserve	60	69	9
Response	226	216	-10
Reactive	62	83	20
Blackstart	18	21	3
Unclassified BM	15	18	3
TLA	0	0	0
BM+AS General	-1	3	4
Reconciliation	2	0	-2
UIOLI		21	
Total	432	757	325

In the Difference column in the above table, an orange background indicates an increase (positive difference) of more than £5m, and a green background indicates a decrease (negative difference) of more than £5m magnitude. Further, only values in bold are summated to give the total. Values in grey are sub-component values or sub-totals: Net Energy is the sum of Energy Imbalance and New NIA; Margin is the sum of STOR, Operating Reserve and BM Start-up; Net Eng + Margin is the resultant sum of Net Energy and Margin; Constraints is the sum of CST – Cheviot, CST – Scot int and CST – Eng Wales.

The reasons for each elements changes are explained in more detail below.

4.2 Energy Forecast

The energy forecast includes the forecast of energy balancing costs and our prediction of New NIA taking into account historic NIV and future pricing.

Our central forecast for 2009/10 is summarised in the following table.

Description	Total	
Mean NIV	-146	MWh
Sum of short NIVs	1,410	GWh
Sum of long NIVs	- 3,962	GWh
Average yearly baseload price	£ 63.26	£/MWh
Average yearly peak price	£ 76.74	£/MWh
Average SPNIRP for short NIVs	£ 75.97	£/MWh
Average SPNIRP for long NIVs	£ 53.31	£/MWh
Average accepted offer	£ 106.36	£/MWh
Average accepted bid	£ 42.64	£/MWh
Total cost of offers	£ 152.54	£m
Total cost of bids	-£ 168.42	£m
Total New NIA for short NIVs	-£ 306.41	£m
Total New NIA for long NIVs	-£ 95.32	£m
Net Energy	-£ 417.61	£m
Total Energy Imbalance Cost	-£ 15.88	£m
Total New NIA	-£ 401.73	£m

The 2009/10 forecast of Energy Balancing costs consists of two elements:

- Volume Forecast
- Price Forecast

4.2.1 Volume Forecast

Volume (NIV) forecasts are created from combining historic outturn data, grouped by EFA block and month, removing extreme points, i.e. the shortest and the longest ones. The use of historic data captures seasonal changes in length – for instance October/November lengthening and March shortening.

For NIV in 2009/10 certain assumptions have been made. These are:

- NIV will follow the same underlying distribution of previous years
- Extreme historical scenarios have been isolated

The NIV forecast is discussed in detail in section 3.1.6. In summary, three different NIV scenarios have been forecast, one considering the shortest observed periods, one considering the longest observed periods and one central scenario, utilised as a base case for this forecast. The long scenario for April uses data mostly from 2006/7, while the short scenario for this month gets its data from 2008/9. The central scenario for April is the average of all four years since BETTA go-live weighted 4:3:2:1 to 2008/9:2007/8:2006/7:2005/6. The central scenario is closer to the short scenario than to the long one due to the market shortening observed in the past years.

4.2.2 Price Forecast

The second part of the Energy Balancing Cost forecast are the prices of energy balancing actions in the Balancing Mechanism (BM) and the Single Price Net Imbalance Reference Price (SPNIRP), each of which varies with wholesale prices. Forward Baseload and Peak prices quoted in Argus European Electricity, 'Daily Electricity Market Prices, News and Analysis' are used as inputs to the model. The forward prices used in the current 2009/10 forecast are as follows:

	UK	
	BSLD £/MWh	PKS £/MWh
Q209	60.60	73.10
Q309	60.00	72.40
Q409	64.60	76.00
Q110	67.80	85.30

(Prices from Argus 17-Oct-08)

National Grid developed internal analysis comparing quarter-ahead prices with day-ahead prices for the same period, reaching a probability distribution that varies as a function of quote lead time. As might be expected, the longer the quote lead time, the greater the probable spread against the day-ahead prices.

Following this analysis, three price scenarios have been developed. The low price scenario assumes that the day-ahead prices will be around 60% (10th percentile of in the probability distribution mentioned in the previous paragraph) of the quarter-ahead prices, while the high price scenario assumes that day-ahead prices will be around 160% (90th percentile of the same distribution) of the quarter-ahead prices. The central scenario simply assumes that day-ahead prices will be exactly the same as the quarter-ahead ones.

Finally, a scaling factor based on historic data has been applied to the quarterly prices in order to obtain monthly prices.

The following table details the price ranges considered for each month:

		BSLD	PEAK	RANGE-	RANGE+
Season	Month	MEAN	MEAN		
Summer	April	£59.84	£72.18	65%	154%
Summer	May	£57.11	£68.89	64%	156%
Summer	June	£64.85	£78.23	64%	157%
Summer	July	£65.07	£78.51	63%	159%
Summer	August	£57.25	£69.08	63%	160%
Summer	September	£57.68	£69.61	62%	161%
Winter	October	£51.09	£60.10	62%	162%
Winter	November	£64.01	£75.31	61%	163%
Winter	December	£75.64	£88.99	61%	164%
Winter	January	£70.90	£89.21	61%	165%
Winter	February	£65.51	£82.42	60%	166%
Winter	March	£70.19	£88.31	60%	167%

4.2.3 Forecast Net Energy Cost

The Energy Balancing Forecast model uses SPNIRP to calculate both the energy balancing costs and New NIA. SPNIRP is defined within National Grid's Transmission Licence and is based on the four-hour and half-hour trade products on the APXUK power exchange for a given settlement period. As this uses market prices it is reasonable to expect this to be strongly correlated with underlying wholesale prices. A model of how SPNIRP relates to Baseload and Peak prices, and to varying market lengths, in each EFA block of each month was created and trained on 2006/7 data. This relationship was then used to derive SPNIRP values for 2009/10 given the forecast NIV distribution.

As it is believed that energy balancing prices also vary with underlying wholesale prices it follows that these prices also relate to SPNIRP. Investigation shows that this gives relatively static results whereby energy balancing prices are 0.8 multiplied by SPNIRP in long markets and 1.4 multiplied by SPNIRP in short markets. Applying this to 2007/8 outturn data gives the following comparison of costs.

	Modeled	Outturn	Yearly Variance	
MWh	Mean NIV	-92	-85	7
GWh	NIV+	1,641	1,689	48
GWh	NIV-	-3,251	-3,184	67
£/MWh	BSLD	£37.58	£37.58	£0.00
£/MWh	PEAK	£45.93	£45.93	£0.00
£/MWh	SPNIRP+	£44.28	£45.19	£0.90
£/MWh	SPNIRP-	£31.83	£33.88	£2.04
£/MWh	BM Offer	£61.99	£61.45	-£0.54
£/MWh	BM Bid	£25.47	£26.16	£0.69
£m	Eng+	£98.52	£103.57	£5.05
£m	Eng-	-£86.76	-£83.18	£3.58
£m	NIA+	-£175.92	-£181.28	-£5.36
£m	NIA-	£54.22	£54.46	£0.24
£m	Net Energy	-£109.94	-£106.43	£3.51
£m	EI	£11.76	£20.39	£8.63
£m	NIA	-£121.70	-£126.82	-£5.12

4.2.4 Volume / Price Scenarios

Combining the three NIV scenarios with the three price scenarios leads to nine possible scenarios for the Energy Balancing Costs, as summarised in the table below (figures in £m)

	Short	Central	Long
Energy Imbalance Low	£ 63.56	-£ 9.84	-£ 87.18
Energy Imbalance	£ 101.25	-£ 15.88	-£ 139.26
Energy Imbalance High	£ 161.43	-£ 25.64	-£ 222.59
New NIA Low	-£ 328.80	-£ 648.11	-£ 430.22
New NIA	-£ 528.80	-£ 401.73	-£ 265.24
New NIA High	-£ 851.06	-£ 249.17	-£ 163.63
Net Energy Low	-£ 265.24	-£ 657.95	-£ 517.40
Net Energy	-£ 427.55	-£ 417.61	-£ 404.51
Net Energy High	-£ 689.63	-£ 274.81	-£ 386.22

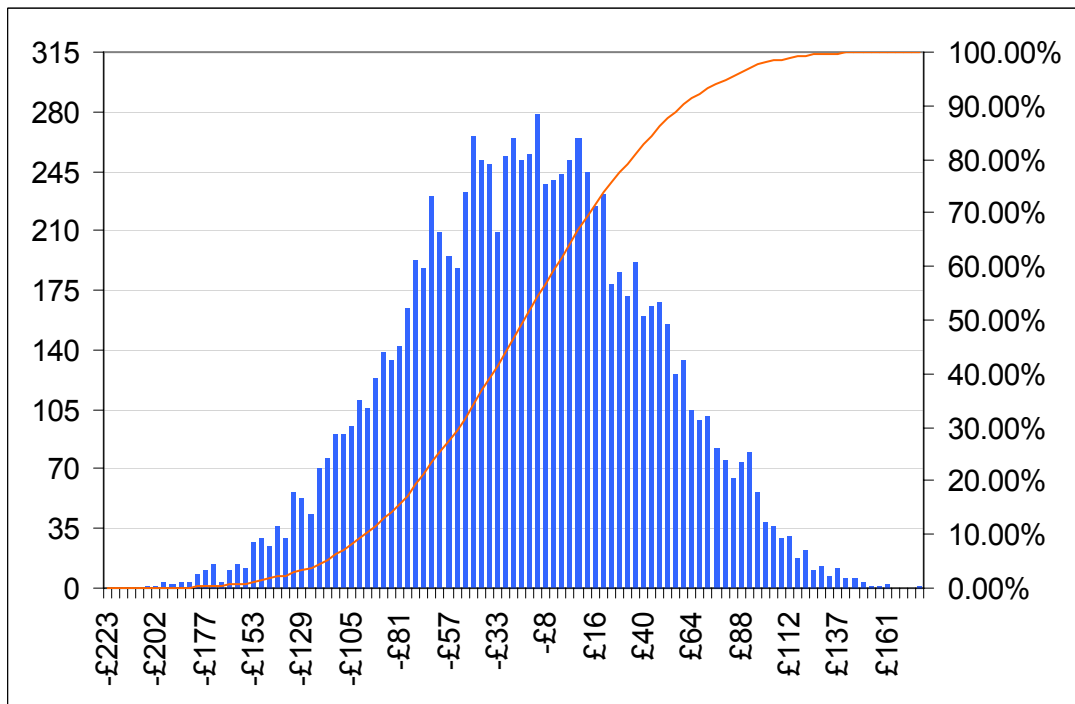
This gives a central scenario of -£418m, with extreme limits of -£265m and -£690m. The overall model result for 2009/10 central NIV scenario is shown on the next page.

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Total
Mean NIV	-149	-178	-102	-47	-131	-138	-204	-212	-125	-185	-167	-111	-146
NIV+	134	101	119	142	95	103	96	93	165	97	110	156	1,410
NIV-	-349	-366	-265	-212	-291	-301	-399	-398	-351	-372	-339	-320	-3,962
BSLD	£ 59.84	£ 57.11	£ 64.85	£ 65.07	£ 57.25	£ 57.68	£ 51.09	£ 64.01	£ 75.64	£ 70.90	£ 65.51	£ 70.19	£ 63.26
PEAK	£ 72.18	£ 68.89	£ 78.23	£ 78.51	£ 69.08	£ 69.61	£ 60.10	£ 75.31	£ 88.99	£ 89.21	£ 82.42	£ 88.31	£ 76.74
SPNIRP+	£ 68.42	£ 70.92	£ 74.95	£ 76.15	£ 62.68	£ 66.76	£ 58.57	£ 77.35	£ 93.52	£ 87.04	£ 84.84	£ 90.50	£ 75.97
SPNIRP-	£ 49.65	£ 47.07	£ 54.33	£ 55.10	£ 49.44	£ 49.57	£ 42.67	£ 52.35	£ 62.14	£ 59.85	£ 56.61	£ 60.86	£ 53.31
BM Offer	£ 95.79	£ 99.28	£ 104.93	£ 106.61	£ 87.76	£ 93.46	£ 82.00	£ 108.30	£ 130.92	£ 121.85	£ 118.77	£ 126.70	£ 106.36
BM Bid	£ 39.72	£ 37.66	£ 43.47	£ 44.08	£ 39.56	£ 39.66	£ 34.14	£ 41.88	£ 49.71	£ 47.88	£ 45.29	£ 48.69	£ 42.64
Eng+	£ 13	£ 10	£ 12	£ 15	£ 8	£ 10	£ 8	£ 10	£ 22	£ 12	£ 13	£ 20	£ 152.54
Eng-	-£ 14	-£ 14	-£ 12	-£ 9	-£ 11	-£ 12	-£ 14	-£ 17	-£ 17	-£ 18	-£ 15	-£ 16	-£ 168.42
New NIA +	-£ 5.12	-£ 7.62	-£ 10.00	-£ 11.34	-£ 9.23	-£ 8.65	-£ 5.79	-£ 6.40	-£ 6.54	-£ 9.22	-£ 6.97	-£ 8.44	-£ 95.32
New NIA -	-£ 26.11	-£ 20.33	-£ 26.33	-£ 31.64	-£ 19.57	-£ 20.18	-£ 16.29	-£ 20.81	-£ 39.55	-£ 24.74	-£ 24.87	-£ 35.99	-£ 306.41
Net Energy	-£ 32.24	-£ 31.67	-£ 35.41	-£ 37.16	-£ 31.95	-£ 31.17	-£ 27.84	-£ 33.79	-£ 41.98	-£ 40.03	-£ 34.08	-£ 40.29	-£ 417.61
EI	-£ 1.01	-£ 3.72	£ 0.92	£ 5.81	-£ 3.15	-£ 2.34	-£ 5.77	-£ 6.58	£ 4.11	-£ 6.07	-£ 2.24	£ 4.14	-£ 15.88
New NIA	-£ 31.23	-£ 27.95	-£ 36.33	-£ 42.97	-£ 28.80	-£ 28.83	-£ 22.08	-£ 27.21	-£ 46.09	-£ 33.97	-£ 31.85	-£ 44.43	-£ 401.73

In the table above, category names with a "+" suffix indicate the value in short markets (NIV>0) whereas a "-" suffix indicates a value in long markets (NIV<0)

New NIA is defined as $(-450 + TQEI \times \{0.9 \text{ (long) or } 1.25 \text{ (short)}\}) \times SPNIRP$ (or $(-450 - NIV \times \{0.9 \text{ (long) or } 1.25 \text{ (short)}\}) \times SPNIRP$), so that the Net Energy is simply Energy Imbalance costs plus New NIA.

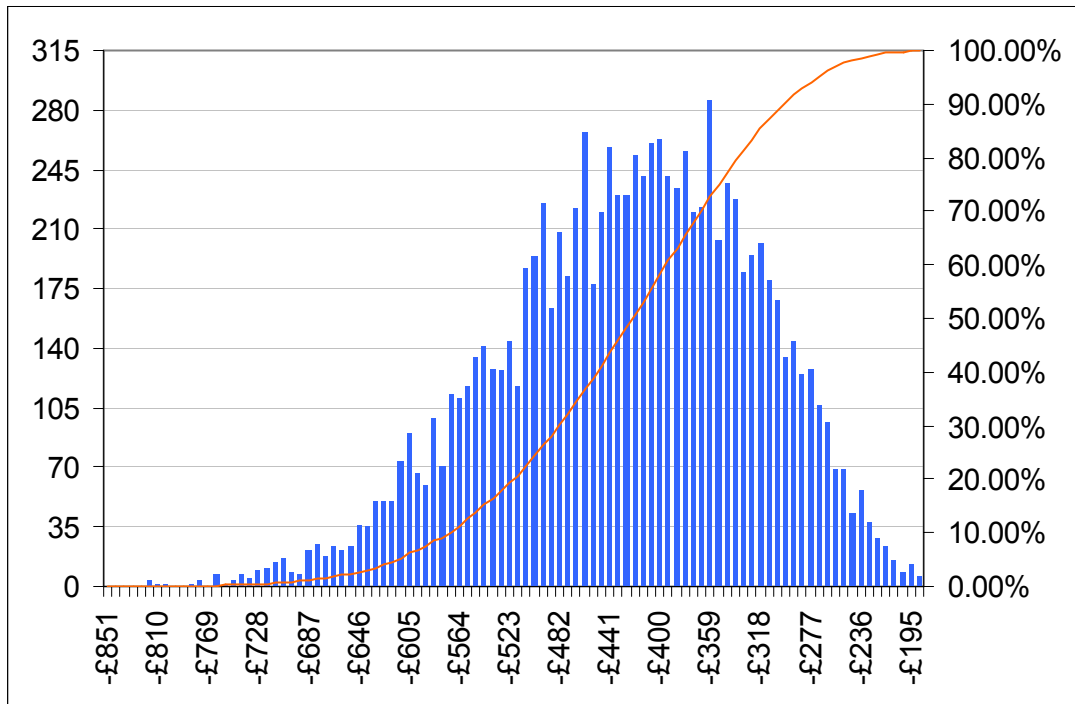
4.2.5 Probability Distribution of Energy Imbalance Costs



P10 = - £95m P90 = -£59m

4.2.7 Probability Distribution of New NIA Costs

Applying the same analysis to New NIA enables us to forecast an equivalent probability distribution for New NIA.



P10 = - £572m P90 = -£298m

In summary, the drivers of net energy remain the forward curve and assumptions of NIV, with the same drivers holding for these elements. Cost for net energy during 2008/09 has out-turned lower than forecast due to the increase in power price. An assumption of lower wholesale prices for 2009/10 from current 2008/09 wholesale out-turn prices has increased this forecast cost. 2008/09 has shown a trend towards a more balanced market. However, this may not continue to hold and, therefore, 2008/09 is not used directly but weighted with the previous three years with a weighting of 4:3:2:1 going back further in time. This also helps to remove extreme volatility.

4.3 Margin

The margin forecast covers the cost of procuring adequate supplies to cover the potential short fall of generation and demand forecast errors. This is made up of three main components, BM start up, STOR and operating reserve. The forecast for these components are detailed below.

As NIV directly feeds into the Margin forecast the same assumptions as Net Energy above apply. A weighting of 10:6:6:3 provides a conservative estimate rather than taking the full impact of the 2008/09 out-turn.

4.3.1 Short Term Operating Reserve (STOR)

STOR is a contracted Balancing Service, whereby the service provider delivers a contracted level of power when instructed. The service can be provided by both BM and non-BM participants. Utilisation of the service from BM participants is via the Balancing Mechanism. For non-BM service providers, a bespoke monitoring and dispatch system (STOR dispatch) is used.

The service falls into two main forms:

1. Committed service and
2. Flexible service

For the committed service, the provider must make the service available for all contracted windows. The flexible service is only open to non-BM service providers. The flexible service providers have greater freedom in nominating their availability windows.

The STOR forecast costs include the BM and non-BM costs.

4.3.1.1 Forecast STOR Costs

The market day for the STOR tender round with the service starting April 2009 is 23rd January 2009. We believe that it would be inappropriate to publish information that may influence the tender submissions, and so this forecast for STOR provides a high level summary of forecast costs.

In summary, we expect to contract more capacity than this year and expect prices to rise in line with previous levels. Therefore the STOR forecast for 2009/10 is £93.0 million. As can be seen from the table below this represents a ~25% increase over this year's costs:

£/Million	05/06	06/07	07/08	08/09	09/10
STOR	53.3	68.4	57.6	74.2	93.0

Before 2007/08 these numbers refer to the spend on the Standing Reserve and Supplemental Standing Reserve services that have been replaced by STOR.

For 2006/07 we held significantly more capacity and therefore the costs were higher for that year and operating reserve costs were correspondingly lower. The particular contract entered into for 2006/07 giving increased capacity has not been offered since.

4.3.2 Forecast Operating Reserve Costs

The Operating Reserve forecast is the cost of providing adequate headroom. The requirements for operating reserve are determined for day ahead timescales down to on the day actions. These costs are separate from STOR, BM start up contract costs, fast reserve and fast start costs.

We forecast the cost of operating reserve over the year by splitting the year into 84 separate sections (one per month, each with seven different fuel types). For each section, we forecast the expected offer price, volume requirement, and value of energy. From these three components we generate the reserve cost forecast:

$$\text{Operating Reserve cost for section} = \text{Volume} \times (\text{Offer Price} - \text{Energy Reference Price})$$

The total operating reserve cost over the year is the sum of the 84 values.

The fuel types used are Coal, Gas, Oil, Hydro, Forward GB Trades, SO-SO Trades and Forward French Trades. The volume forecast is an average of the appropriate outturn data since April 2005 with adjustments to reflect future plant operating reserve. A detailed derivation of the (per fuel) reserve price forecast is given in section 4.3.2.1 below. Finally, the energy reference price is derived from the Energy forecast above.

The total forecast spend for Operating Reserve is £314m, a break down (per fuel-type and month) is given below.

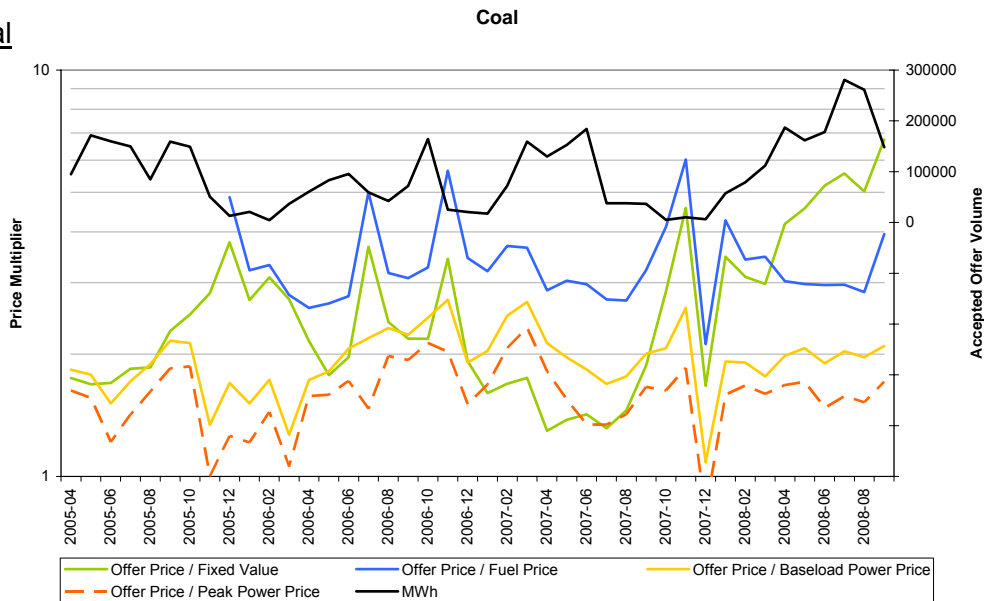
4.3.2.1 Operating Reserve Price Forecast Methodology

This section provides further detail of our analysis of likely prices for Operating Reserve plant for dispatch on the day. To do this, we analysed the ratio of the prevailing price of reserve actions. The three variables we analysed were: The underlying fuel cost; wholesale baseload price; and peak prices. This analysis is shown in the graphs below for each fuel type, Coal, Oil and Gas. The price forecast is then based on the best correlation, being either:

1. Correlated with associated fuel price.
2. Correlated with wholesale electricity price (baseload and/or peak)
3. If no correlation with the above two variables then we assume a fixed price based on historic levels.

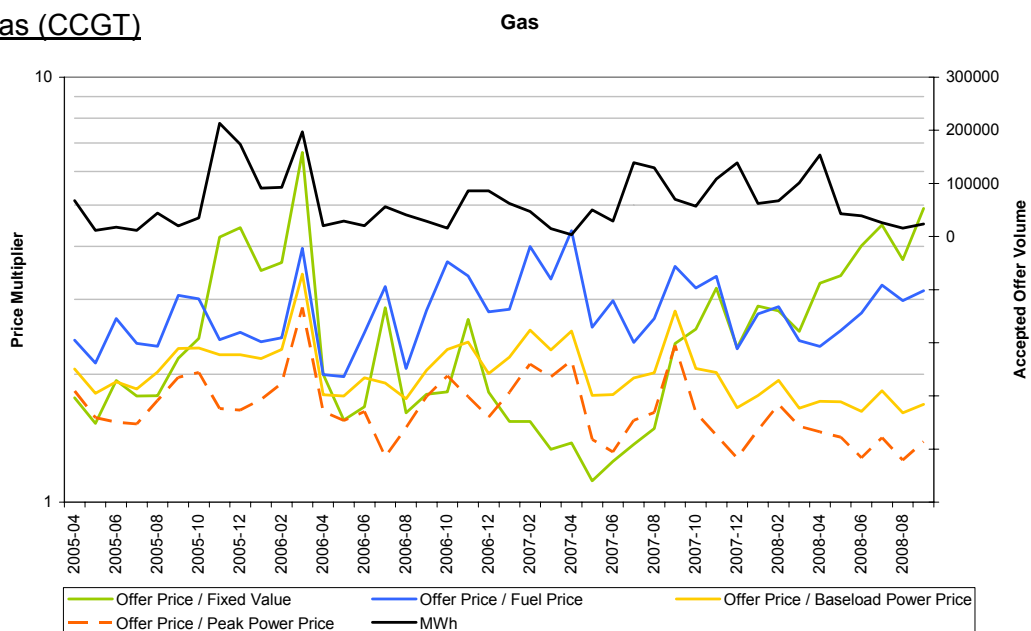
Note: In all graphs price is the Offer price of operating reserve actions which is then divided by one of the above variables to give a multiplier value, shown on the left hand scale. Volume is shown on the right hand scale.

Coal



- For coal, the most consistent relationship throughout the year is with wholesale price
- Coal Offer Price by month approximately equal to 2 multiplied by the baseload power price

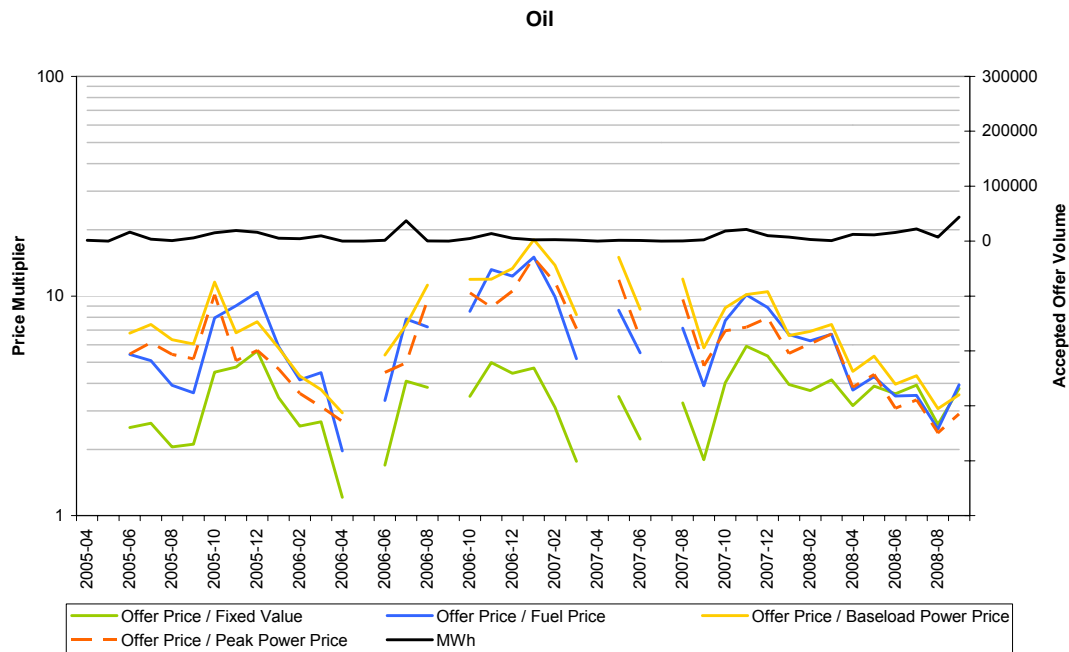
Gas (CCGT)



There is a good relationship between the operating reserve price of gas fired plant and fuel price. The relationship derived is:

- In most months, gas generation operating reserve price is 2.5 to 3.5 multiplied by the gas marginal fuel cost.
- Therefore, for future operating reserve prices, we have used the forward fuel price (including Carbon) to forecast the marginal gas fuel price
- The operating reserve price multipliers have been used to calculate our forecast prices for gas plant supplying reserve.

Oil



- For Oil plant there is no correlation with underlying fuel costs or wholesale prices, therefore we have assumed two fixed prices, one for the summer and one for the winter.

Trades on the French Interconnector

Historically the achieved trade price for purchasing operating reserve over the French Interconnector is 1.5 multiplied by the forward French power price. This factor reflects the fact that the days we purchase the power are correlated with the higher on-the-day French price.

4.3.2.2 Operating Reserve Cost Detail

The table below provides an overview to the price assumptions used in the forecast.

		April	May	June	July	August	September	October	November	December	January	February	March	Total
Offer Price	Coal	Offer Price	119.68	114.22	129.70	130.13	114.50	115.37	114.95	176.03	132.38	141.81	131.03	140.39
		Multiplier	2.00	2.00	2.00	2.00	2.00	2.00	2.25	2.75	1.75	2.00	2.00	2.00
		Baseload Power Price	59.84	57.11	64.85	65.07	57.25	57.68	51.09	64.01	75.64	70.90	65.51	70.19
	Gas	Offer Price	145.39	138.77	157.57	156.06	137.31	138.35	154.59	221.36	196.20	225.49	208.34	223.23
		Multiplier	3.00	3.00	3.00	3.00	3.00	3.00	3.50	4.00	3.00	3.50	3.50	3.50
		Forward Fuel Price converted to £/MWh	48.46	46.26	52.52	52.02	45.77	46.12	44.17	55.34	65.40	64.42	59.53	63.78
	Oil	Fixed Value	350.00	350.00	350.00	350.00	350.00	350.00	350.00	457.00	457.00	457.00	457.00	457.00
	Hydro	Fixed Value	175.00	175.00	175.00	175.00	175.00	175.00	175.00	175.00	175.00	175.00	175.00	175.00
	UK Trade	Peak Power Price	72.18	68.89	78.23	78.51	69.08	69.61	60.10	75.31	88.99	89.21	82.42	88.31
	French SOSO	Fixed Value	90.00	90.00	90.00	90.00	90.00	90.00	90.00	90.00	90.00	90.00	90.00	90.00
	French Trades	Trade Price	97.59	93.15	105.77	118.67	104.41	105.21	116.62	146.12	172.68	160.69	148.47	159.08
		Multiplier	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50
Peak Power Price (French price converted to £/MWh)		65.06	62.10	70.51	79.12	69.61	70.14	77.75	97.42	115.12	107.13	98.98	106.05	
Energy Balancing Price	Pseudo Price (£/MWh)	71.23	67.74	76.88	77.26	66.59	68.56	59.63	69.61	85.20	79.92	75.48	81.74	
Volume (MWh)	Coal	139,612	143,301	154,875	182,090	130,373	131,330	149,765	100,656	81,299	61,942	68,348	74,894	1,418,484
	Gas	58,125	59,661	64,480	75,810	54,279	54,677	62,352	197,588	159,590	121,592	134,167	147,016	1,189,336
	Oil	7,594	7,795	8,425	9,905	7,092	7,144	8,147	16,394	13,242	10,089	11,132	12,198	119,156
	Hydro	31,394	32,224	34,826	40,946	29,317	29,532	33,677	57,246	46,238	35,229	38,872	42,594	452,095
	UK Trade	31,530	32,363	34,977	41,123	29,443	29,659	33,822	40,039	32,339	24,640	27,188	29,791	386,913
	French SOSO	6,363	6,531	7,058	8,298	5,941	5,985	6,825	15,771	12,738	9,705	10,709	11,734	107,658
	French Trades	20,683	21,230	22,944	26,976	19,314	19,456	22,187	19,169	15,483	11,796	13,016	14,263	226,518
	Cost (£)	Coal	4,980,727	6,660,577	8,180,326	9,627,668	6,245,016	6,147,643	8,284,314	10,711,626	3,835,633	3,833,523	3,796,447	4,392,494
Gas	4,310,458	4,237,182	5,202,546	5,973,726	3,838,095	3,816,155	5,920,924	29,985,021	17,714,598	17,699,631	17,825,390	20,800,947	137,324,672	
Oil	2,117,055	2,200,166	2,300,897	2,701,450	2,009,830	2,010,549	2,365,510	6,351,037	4,923,278	3,804,288	4,247,126	4,577,543	39,608,729	
Hydro	3,257,784	3,456,170	3,417,133	4,002,025	3,178,082	3,143,407	3,885,342	6,033,313	4,152,326	3,349,508	3,868,478	3,972,424	45,715,992	
UK Trade	29,983	37,150	47,066	51,530	73,150	31,070	15,971	228,110	122,755	228,786	188,746	195,837	1,250,154	
French SOSO	119,427	145,341	92,596	105,710	139,062	128,328	207,281	321,594	61,196	97,819	155,481	96,943	1,670,779	
French Trades	545,256	539,274	662,760	1,117,117	730,407	713,056	1,264,512	1,466,731	1,354,505	952,791	950,076	1,103,113	11,399,596	
Total		15,360,690	17,275,860	19,903,324	23,579,225	16,213,641	15,990,208	21,943,854	55,097,432	32,164,291	29,966,345	31,031,744	35,139,300	313,665,915

4.3.2.3 Effect of LCPD on Reserve Costs

The change in running regime of LCPD generation will have an effect on the procurement of reserve services. Currently, there is approximately 8 GW of opted out coal plant that has significantly changed its operating regime.

The change in operation of a portion the 8GW of opted-out coal plant capacity has increased the cost of marginal energy actions. This increase in costs is included within the reserve forecast.

Under LCPD, coal and oil plants had three options:

- Continue to run with a limited life derogation, with 20,000 hours of operation between 1st Jan 2008 and 31st Dec 2015 (a total of 70128 hours) – Opted Out
- Comply with an Emission Limit Value (ELV) set by the directive which defines concentration based controls with 48 hour and monthly mean levels to be met
- Comply with a National Emissions Reduction Plan (NERP), a mass based annual emission limit.total per year limit

Both the ELV and NERP options would normally require the power station to fit Flue Gas Desulphurisation (FGD) to remove sulphur oxides from the products of combustion before releasing them to environment via the chimneystack.

The options chosen by GB coal and oil plant are shown below:

Power Station	Option Chosen
Aberthaw	ELV
Cockenzie	Opted Out
Cottam	ELV
Didcot A	Opted Out
Drax	NERP
Eggborough	NERP
Fawley	Opted Out
Ferrybridge Units 1&2	Opted Out
Ferrybridge Units 3&4	ELV
Fiddley's Ferry	ELV
Grain	Opted Out
Ironbridge	Opted Out
Kingsnorth	Opted Out
Littlebrook	Opted Out
Longannet	ELV
Ratcliffe	ELV
Rugeley	ELV
Tilbury	Opted Out
West Burton	ELV
Uskmouth	ELV

4.3.2.4 Effect of Wind on Reserve Costs

In operating the system in real time, we procure energy to ensure that it can secure the system for the loss of generation or for demand forecast errors. The expected increase in intermittent generation is likely to increase the volatility of generation and hence increase the reserve requirements.

Our initial assessment indicates that for the additional volumes of wind generation connecting in 2009/10 there will be a cost of £12m - £25m with a central forecast of £17m.

It should be noted:

- That the analysis implicitly assumes that the market will self balance up to Gate Closure, and that NGET will balance post Gate Closure.
- That the analysis is using the wind error on the metered wind farms and extrapolating across all GB wind farms. It is noted that going forward there are projects planned to improve metering.

Although it is anticipated that other generation plant (thermal and hydro) will vary its output to compensate for variations in wind output, the magnitude of any impact on our energy requirements will depend on the ability of the market to compensate for variations in wind output through short-notice changes.

4.3.3 Forecast BM Start-Up costs

The BM start-up service is a mechanism for us to access generation in the BM which is not otherwise planning to run. The service contains two elements; BM start-up and hot standby.

BM start-up is associated with bringing a BM Unit to a state where it can synchronise within BM timescales. Hot standby is associated with holding the BM Unit in such a state of readiness.

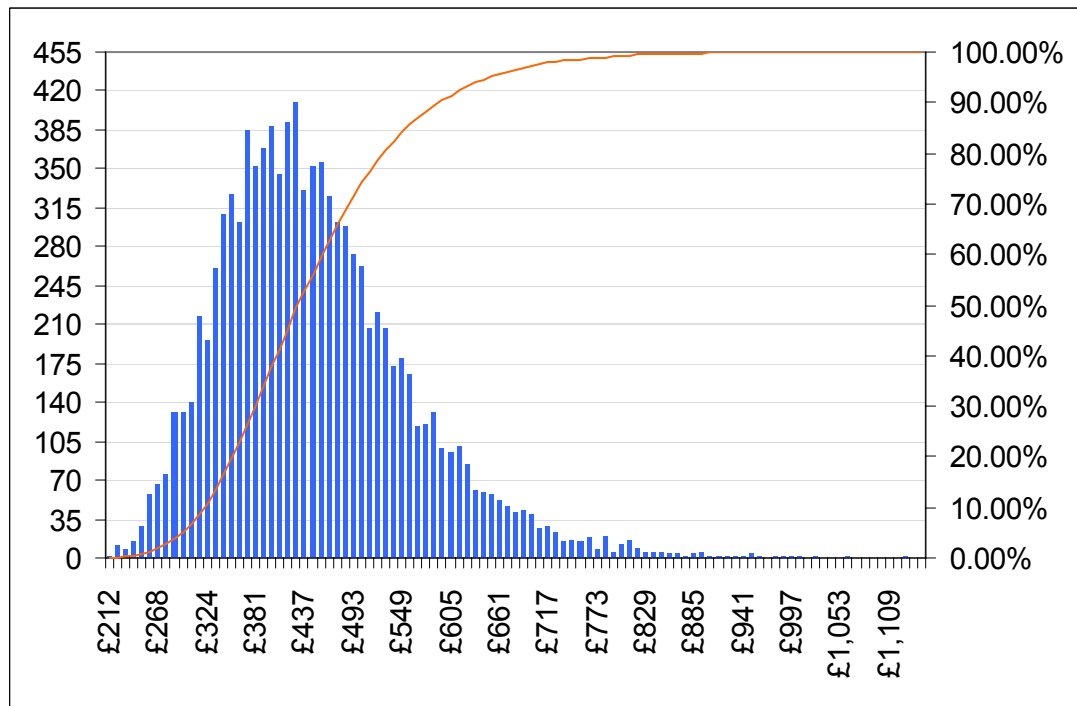
The BM start-up service was initiated in late 2006. A similar service in place prior to 2006 was Warming. The cost table below compares the historic warming costs with the forecast BM start-up costs.

£/Million	01/02	02/03	03/04	04/05	05/06	06/07	07/08	08/09	09/10
BM Start Up	9.4	30.4	21.1	16.2	7.4	11.9	14.8	19.5	23.0

Our forecast of BM Start Up costs for 2009/10 is £23m, up 18% from 2008/09. The increase is mainly associated with the forecast change increase in requirement in line with the Reserve forecast below. This forecast increase is the smallest percentage increase since BETTA.

4.3.4 Probability Distribution of Margin Costs

The probability distribution for total margin (STOR + Operating Reserve + BM Startup) costs is shown in the following graph:

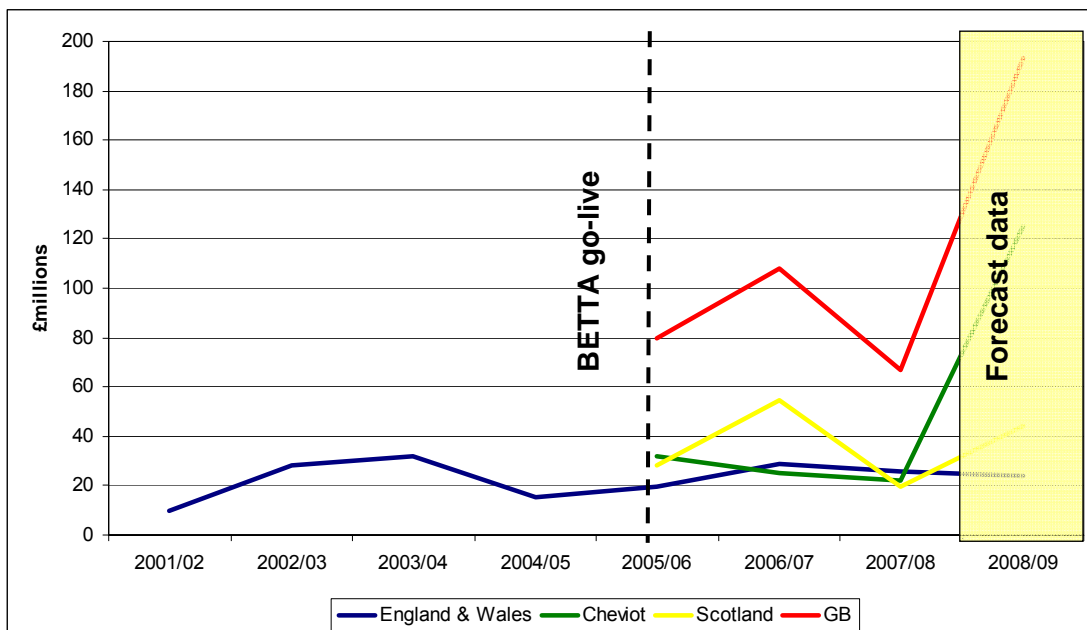


P10 = £321m P90 = £591m

In summary, the drivers for the cost of margin remain the same as in 2008/09 during which time we saw a large increase due to loss of response provision and headroom. These factors remain during 2009/10, although to a lesser extent due to the forecast return of one service provider, and with an increase in STOR volume and prices the margin cost in this current forecast has increased.

4.4 Constraint Costs

The graph below shows constraint costs since the start of NETA:



Constraint costs for the GB transmission system were £70 million in 2007/8 and are forecast to be £193 million for 2008/9. A significant proportion of these costs are incurred as a result of constraints on the Scottish transmission system or on the Cheviot (Scotland to England) boundary: £41.6 million in 2007/8, and forecast to be around £169 million for 2008/9.

Forecast Summary for 2009/10

Network constraint costs are forecast to total £307 million for 2009/10. The breakdown of these costs is shown in the table below.

£m	England & Wales	Cheviot	Scotland	GB
2008/9 forecast outturn	24	125	44	193
2009/10 forecast	65	161	81	307

The following sections describe in more detail the forecasts for the three elements.

4.4.1 Constraint Forecasting Approach

For modelling purposes, we divide the GB transmission system into two parts, Scotland, and England & Wales, to reflect the GB transmission network topology and the nature of constraints identified. We then break down Scotland into the Cheviot Boundary and Internal Scotland for reporting/monitoring purposes.

For both the Cheviot boundary and Internal Scotland, we use a probabilistic model, which combines distributions of Scottish generation with forecast demand levels and Cheviot boundary flows with the boundary's capability.

Due to the multiplicity of possible constraint boundaries in England & Wales a probabilistic model to forecast constraint costs is more complex. For this forecast, we have therefore adopted an alternative approach based on:

- 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 the following are studied and the impact on constraints assessed.
 - Directional flows on the French Interconnector
 - Running patterns of LCPD plant
- Key outages and/or transmission boundaries that cause significant constraint costs are identified

4.4.2 Scotland Forecast Model

For 2009/10, the key forecast assumptions are:

- The model uses probabilistic Scottish generation profiles that reflect historical trends and anticipated plant outages;
- There is an increase in the total number of planned outage weeks in Scotland and Cheviot from 30 in 2008/9 to 36 weeks in 2009/10, with the additional 6 weeks occurring after the autumn clock change.
- Forecast bid / offer prices and associated replacement costs.
- Average Scottish wind capacity visible to National Grid is forecast to rise from the current (November 2008) 1450MW to 1822MW during summer 2009, with load factors varying month on month but range between 20% and 30%. In

winter there is a forecast capacity of 2383MW with load factors ranging between 25% and 40%.

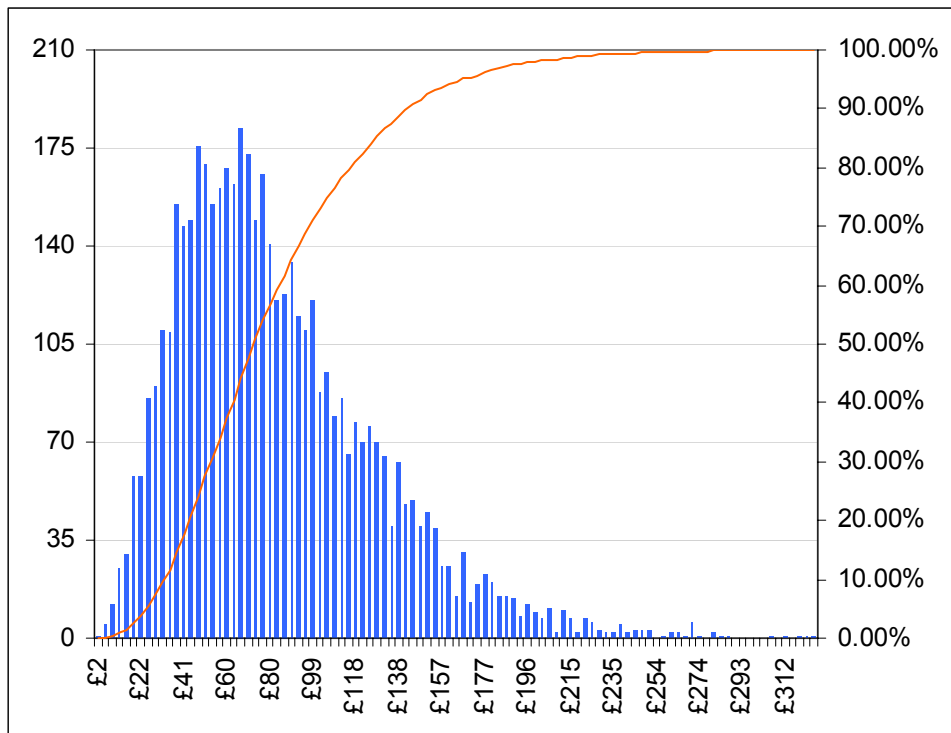
- Utilisation of the existing system to generator intertrip scheme where economically viable at the current pricing level. This intertrip scheme will be on outage for four weeks over the summer.
- A historical percentage of constraint volumes contracted forward of the BM.

4.4.3 Within Scotland

We experience a number of constraints within the Scottish Hydro Electric Transmission Limited, SHETL and the Scottish Power Transmission Limited, SPTL transmission systems that impact 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.

The outage program for 2009/10 affects a number of critical constraint boundaries across the Scottish network. There continues to be considerable Transmission Investment for Renewable Generation (TIRG) works, as in 2008/09. The associated outages increase the risk on constraint volumes.

The graph below represents the cost risk profile for internal Scottish constraints.



P10 = £33m P90 = 141m

The central cost forecast for within Scotland constraints is £81m. The graph shows an 80% probability of a range of costs from £32m - £140m, indicating the extent of the uncertainty surrounding the forecast.

The range outlines the risk with volumes. Generation and demand patterns can change from those forecast depending on many factors e.g. generation planned maintenance, market conditions.

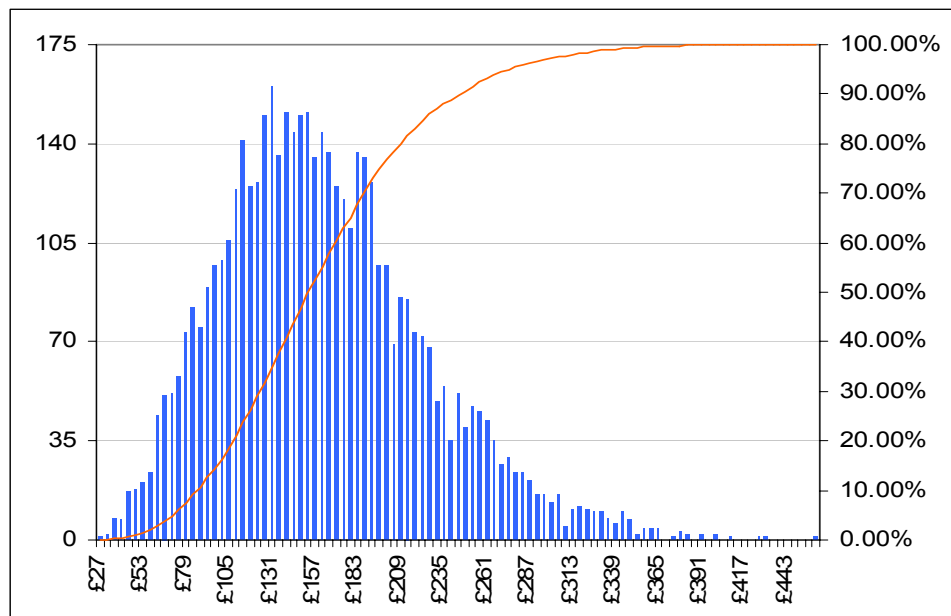
It should be noted that there is no allowance in the model for any outage overruns within Scotland or on the Cheviot boundary. During 2008/09 significant overruns occurred on a number of outages.

4.4.4 Cheviot Boundary

The Cheviot boundary is a critical constraint boundary located between Scotland and England. For intact conditions there is a limitation on the power that can flow across the boundary due to thermal, system stability and voltage issues. For outage conditions, this limitation is significantly exacerbated.

There are considerable construction works planned to upgrade the capability of the Cheviot boundary between 2008 and 2013. These outages are mainly associated with TIRG construction works and will be more onerous in terms of duration and restriction than a typical maintenance plan would necessitate. During 2009/10 there are a number of TIRG outages that will limit the export capability of the Scottish system, hence increasing the constraint costs.

Against the assumptions in section 4.4.2, our model forecasts a total Cheviot cost of £161m. The 80% probability range of the overall cost is from £86m to £243m. The cost distribution is shown below.



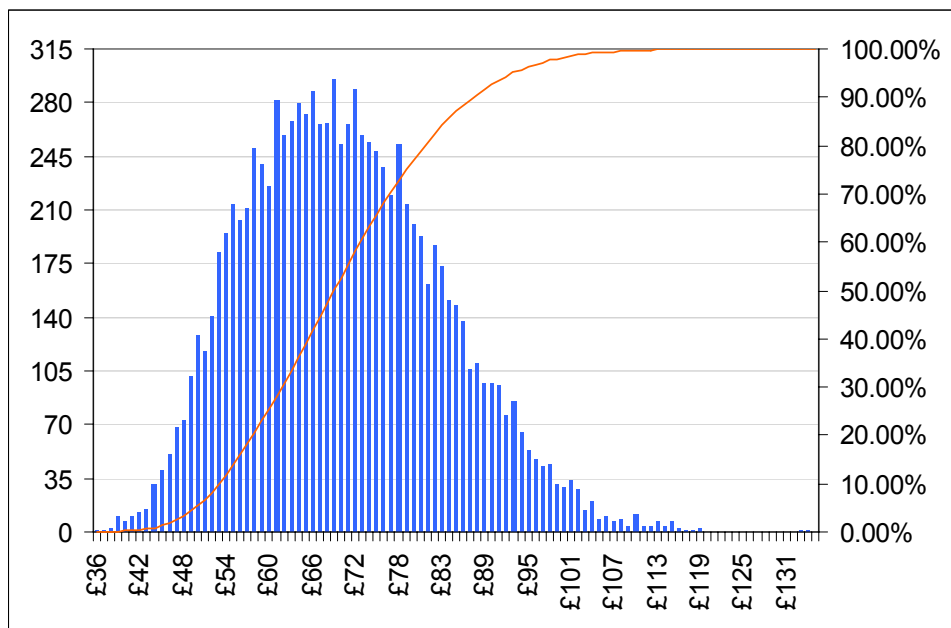
P10 = £87m P90 = £244m

The above graph indicates the range of potential costs associated with the Cheviot boundary constraint and the corresponding risk. The risks are mainly associated with the constraint volumes. These are affected by plant availability and market conditions.

4.4.5 England & Wales

Our initial assessment of the indicative outage plan covering England and Wales indicates a significant increase in costs compared to the forecast 2008/09 outturn. The current forecast for 2009/10 is £65m, which amounts to an increase of £41 million. The increase is associated with the following: An increased volume of transmission infrastructure works; the expectation of a reduction in import volumes to GB from France when compared to 08/09; less favourable dispatch patterns across LCPD opted out plant, as this plant is predominantly in located in the south of England.

4.4.5.1 Probability Distribution of England & Wales Constraint Costs

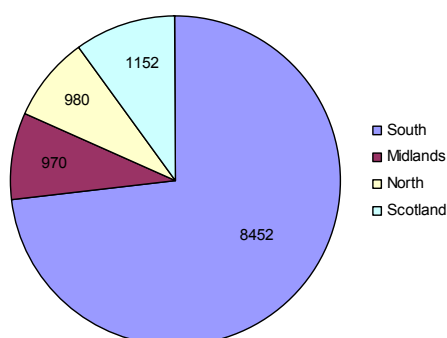


P10 = £49m P90 = £84m

4.4.6 LCPD Effect on Constraints

The impact of LCPD opted out plant running behaviour continues to provide a lot of uncertainty when forecasting constraint costs. Throughout 2008, some of the LCPD opted out plant has run more hours than would have been expected assuming an even spread of operating hours for closure in 2015. The expectation is that with the commissioning of delayed Flue Gas Desulphurisation, (FGD), and the reduction in forward prices, the utilisation of opted out plant will reduce from what has been observed to date.

LCPD Generation Location



Assessment of the impact on national-level constraints is due to the fact that, of the 11.5GW of opted plant, 8.5GW is located in the Southern part of the system. During the periods where there is an active constraint with opted out units choosing not to run, the generation that will replace this energy will be spread throughout the country. This will increase pressure on all our major North–South network constraints with the system both intact and under outage conditions.

There is also a more unpredictable localised constraint cost effect that has resulted from the introduction of LCPD. With the units at opted out generation stations, operating as either all on or all off, as described above, there is an increased risk of localised constraints being activated which need to be secured through additional balancing.

Summary of GB Constraint Forecast

The below summarises the total GB constraint costs since 2001/02 compared to the latest forecasts.

£m	England & Wales	Cheviot	Scotland	GB
2001/2	9.9			
2002/3	28			
2003/4	31.6			
2004/5	15.1			
2005/6	19.6	31.6	28.5	79.7
2006/7	28.6	24.9	54.6	108.1
2007/8	28.5	22	19.6	70.1
2008/09 forecast outturn	24	125	44	193
2009/10 forecast	65	161	81	307

In summary, constraints are driven in the main by volume which is derived by the planned outage programme which varies significantly year on year. No allowance for over-run or unplanned outages has been applied to the forecast.

The 2009/10 constraint forecast uses a combination of historical constraint volumes (when the circuit has been out in the past), system studies, and expectation of plant generation which is based on historical running patterns. Replacement costs have

been calculated using a combination of forward fuel prices and their historical link to energy/margin costs.

In Scotland, there is an increase in wind capacity where assumed historical wind load factors have been applied. In Scotland, the increase in expected 2009/10 costs is mostly driven by how we can resolve the constraints next year due to the nature of the outage plan, the main cause being unable to use the inter trip to solve constraints as much as we have this year. In England and Wales, the significant increase is volume driven based on the nature of the outage plan for next year.

4.5 Fast Reserve

Fast reserve provides rapid delivery of active power through an increased output from generation or the reduction in demand following a dispatch instruction. Fast Reserve is procured either via a monthly tender process or by issuing a Bid Offer Acceptance in the Balancing Mechanism on a generator with suitable Dynamics.

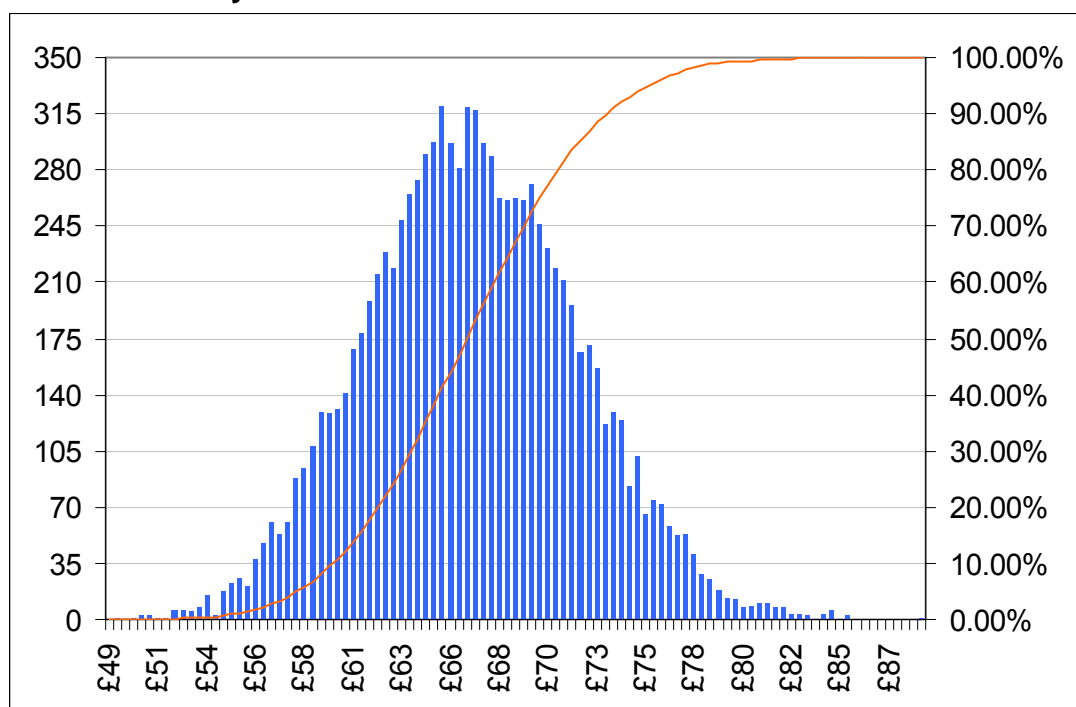
The main factors driving the costs of fast reserve are the number of providers and contracts terms and conditions.

Several Fast Reserve service providers were restricted/ unavailable in 2008/9 due to planned and unplanned outages on both the transmission system and the providers' system. It is assumed that Fast Reserve service provider's availability will improve and be sufficient to meet the anticipated levels of utilisation.

Historical costs are shown below with the forecast for 2009/10. (2008/9 is part out-turn and part forecast.)

(£m)	2005/6	2006/7	2007/8	2008/9	2009/10
Total	51.0	58.5	58.3	59.5	68.9

4.5.1 Probability Distribution of Fast Reserve Costs



P10 = 63m P90 = 76m

In summary, forecast volume has been based on an extrapolation of the underlining trends since 2005/6, as was the 2008/09 forecast which remains on track with current outturns. Price is driven by tendered contract prices and is largely independent from changes in power price. Forecast tendered contract prices have been based on historic tendered and contracted prices.

4.6 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 us 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 our view of the cost of mandatory response and the likely cost of alternative sources of frequency response.

Mandatory prices have been submitted monthly under the current pricing arrangements since November 2005. The latest response price and utilisation data can be found on our Industry Information website, within the balancing services section.

For Balancing Mechanism Units (BMUs) submitting combined prices (primary plus secondary plus high) below £30/MW/h, the mandatory market has seen prices stabilise since June 2007. Providers are maintaining their prices on the high service with primary and secondary prices moving towards pre-CAP047 levels.

We have considered a number of potential cost drivers for mandatory frequency response:

- Fuel costs
- Risk of energy price exposure
- Seasonal effects on submitted prices

Our analysis has not found any clear drivers behind submitted price changes. For our forecast, we have assumed that prices remain stable for the following year.

4.6.1 Price Assumptions for Frequency Response

These assumptions are our central forecast. There are some risks associated with these assumptions. These are covered in more detail in 4.2.4.

- Forward mandatory prices are derived by extrapolating prices from post-CAP047 levels
- Prices for alternative response procurement are consistent with the mandatory price forecast
- Response energy costs to remain stable
- BOA costs will decrease from forecast 2008/09 forecast outturn levels due to decline in power prices

4.6.2 Volume Assumptions for Frequency Response

The forecast assumption is that the volume of frequency response for 2009/10 will remain stable.

4.6.3 Forecast Frequency Response Costs

£m	04/05	05/06	06/07	07/08	08/09 Forecast	08/09 Outturn	09/10 Forecast
Mandatory Costs	24	37	76	69	69	83	84
BM Costs	12	17	36	26	24	91	75
Contract Costs (including response energy)	20	29	48	55	52	52	57
Total	56	83	160	150	145	226	216

The above table outlines the central forecast for frequency response costs for 2009/10. There is a risk associated with each element of the above costs. The table below indicates our risk range for frequency response costs.

There are a number of risks associated with the above forecast. The table below outlines the cost range for frequency response costs and the assumptions associated with that range.

£m	Mandatory Costs	BM Costs	Contract Costs (including response energy)	Total	Assumption
High	89	126	72	287	Reduced static providers Price increases; short NIV
Medium	84	70	62	216	Response price rises with RPI Mandatory volumes stable Central NIV and power prices
Low	63	37	56	156	Mandatory costs decrease by 5% Long NIV, low price

The above assumptions indicate that we believe that there is a higher risk of costs increasing than decreasing. This is mainly associated with the risk of mandatory prices increasing as compared with decreasing.

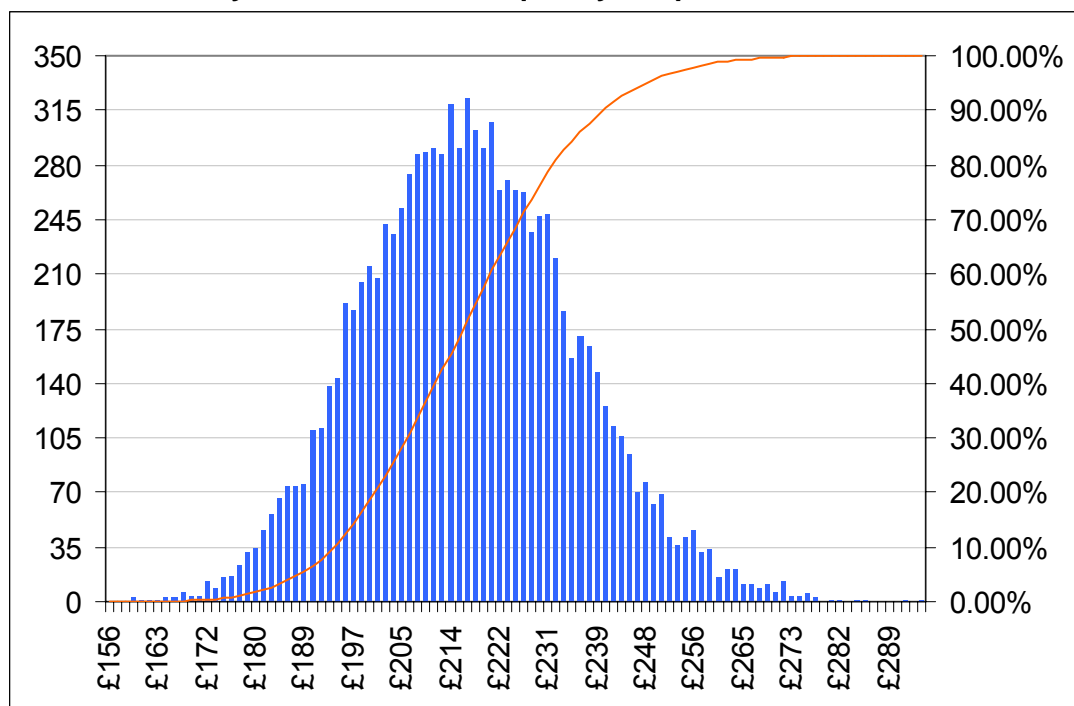
Combining the scenarios with a Monte-Carlo technique to give a probability distribution, we believe the overall range of costs, at 80% confidence, is estimated to be £194m - £240m. This compares to a forecast outturn for 2008/09 of £226m.

4.6.4 Effect of Wind on Response Costs

With the predicted increase in wind generation for next year, we do not think that dynamic response levels will have to increase in all timescales. However there may be a number of days across the year where the variability of wind results in frequency control becoming more difficult. Under these conditions it would be prudent to increase the dynamic response holding.

Our forecast assumes that we require additional response on high wind output days, approximately 20 days across the year. This results in a total cost for additional response of approximately £2.5m. This cost is included in the total response forecast above.

4.6.5 Probability Distribution of Frequency Response Costs



P10 = £194m P90 = £240m

In summary, there are three main drivers for the cost increases over forecast during 2008/09. These are the reduced availability of static response providers, the extension of transmission system outages in North Wales, and higher than expected power prices at times of short market length. These will continue to apply to a lesser extent for 2009/10, with a forecast increase in availability of static response providers towards historic levels, and a reduced volume of Welsh outages. For mandatory response we are forecasting a small increase in submitted Cap47 prices.

4.7 Reactive Power

Reactive Power is split into mandatory and commercial. The majority of costs are associated with mandatory service. The price paid to mandatory providers for reactive power is outlined in the CUSC. The price is linked to the power price and RPI. Therefore our forecast for Reactive Power costs is based on a straight calculation of prices based on projected power prices and an estimated RPI.

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.

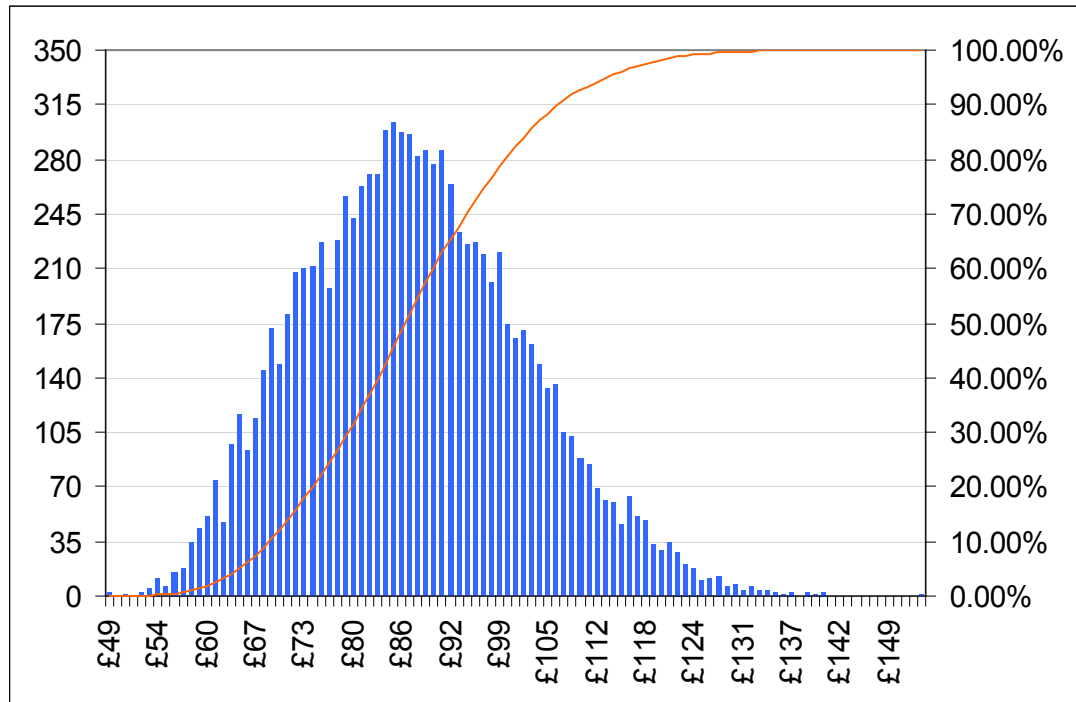
4.7.1 Assumptions for Reactive Power

- The system reactive demand for 2009/10 is normalised to average conditions
- Forward power prices as outlined earlier have been used to determine the price of reactive power
- RPI estimated at being 4.5% for 2009/10. This is the average RPI in 2008/09 to date according to the Office of National Statistics. Visual inspection of graphs forecasting CPI in the Bank of England's November Inflation Report suggest average CPI for 2009/10 will lie in the range -0.5 to 3%, with a mean forecast around 1.5%. Data from the Office of National Statistics shows that in the last 12 months the relationship between RPI and CPI has varied between RPI having a similar value to CPI to RPI being twice CPI. The Bank of England does not forecast RPI.

4.7.2 Forecast Reactive Power Costs

The difference in reactive costs between 2008/9 and 2009/10 is a combination of power price change and system demand in 2008/9 being much lower than average. The forecast for 2009/10 is £83m compared to £62m for 2008/09. Note that the £62m 2008/09 figure does not take account of the current high power price for winter 2008/09, otherwise the 2008/09 outlook will be circa £77m, which is lower than the 2009/10 forecast due to low out-turn volume in summer 2008.

4.7.3 Probability Distribution for Reactive Power Costs



P10 = 66m P90 = 103m

In Summary, forecast volume has been based on ACS demand and the historic relationship between generator reactive volume and system demand. Price is mainly driven by forward power price using the calculation defined in the CUSC. The forecast methodology considered the high-level relationship between generator reactive volume with system demand between 2005/6 and 2008/9, so an average plant mix from this period has also been assumed. The complex relationship between reactive volume and system outages, generator outages, system demand and plant mix means a more detailed forecast model is not expected to yield higher accuracy. Therefore, the exact plant mix would not have a significant impact on the forecast model.

4.8 Black Start

Costs for Black Start services for 2009/10 are projected to be £21m. The increase in this compared to the £17m initially forecast for 2008/9 is due to anticipated increases to the contract terms from the renewals that are due over the next few months. This also includes increases that have already occurred on account of contract renegotiations during 2008/9.

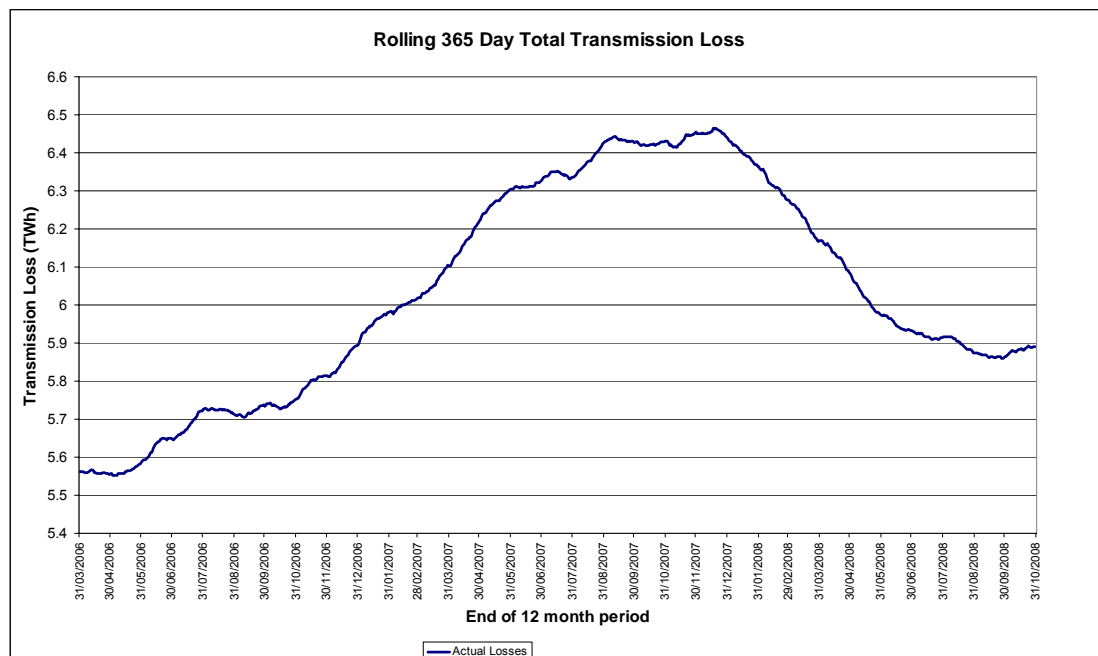
4.9 Other

Each year we incur miscellaneous other balancing costs, which include Trading fees, and liabilities for services used which we do not manage to settle within-year. In addition, there are actions taken in the BM that do not simply fall into one of the balancing services categories used in our reporting. In total, costs in this area are currently forecast at £18m in 2008/09, which is £5m higher than initially forecast for the year. We anticipate a small increase to £21m for 2009/10 on the back of marginally higher power prices and reflecting the increases seen this year.

4.10 Transmission Losses Forecast

Transmission losses occur when power is transmitted across the transmission system. The main element of transmission losses is associated with heating losses in transmission equipment caused when current passes through the equipment. There are many elements that affect the volume of transmission losses; transmission equipment design, transmission topology, generation location and demand. By far the main driver of transmission losses is the generation location.

Transmission losses have risen in recent years, rising to a peak total loss over a 365 day period of 6.46 TWh. In recent months losses have declined from this value, currently running at a value of 5.89TWh for the 365 days up to 23rd October 2008. This decline is explained in the report on transmission losses published by National Grid in June 2008⁹. The losses are presented graphically below.



⁹ <http://www.nationalgrid.com/NR/rdonlyres/4D65944B-DE42-4FF4-88DF-BC6A81EFA09B/26920/ElectricityTransmissionLossesReport1.pdf>

Transmission Losses Forecast

The transmission loss (TL) forecast is based upon an algebraic function of geographical disposition of generation developed in 2008 and described on the National Grid website.

In this model, the country was initially divided into ten zones, based upon an analysis of the effect of changes in generation in every individual power station on total losses. It was found that amalgamating the ten zones into five did not significantly affect the results of the model.

The eleven coefficient, five variable quadratic model is judged to give the best compromise between model accuracy and complexity.

The model is:

$$\begin{aligned} \text{TL} = & 195.4 \\ & + 0.0000210120 T_{1,3}^2 & + 0.014044 T_{1,3} \\ & + 0.000006484457 T_{2,4}^2 & + 0.012549 T_{2,4} \\ & + 0.000000565834 T_{5,7}^2 & + 0.010096 T_{5,7} \\ & + 0.00000430689 T_6^2 & + 0.002219 T_6 \\ & + 0.00000407911 T_{8,9,10}^2 & + 0.006105 T_{8,9,10} \\ & + \varepsilon \end{aligned}$$

Where

TL = the transmission loss (in MWh) for a particular half-hour.
T_{1,3} = total generation in zone 1 + total generation in zone 3
– total offtake in zone 1 – total offtake in zone 3.
(all values in MWh)
T_{2,4}, T_{5,7}, T₆ and T_{8,9,10} are defined similarly.
ε = the model error.

This model has a standard error per settlement period of 31 MWh, and a daily standard error of 1.3 GWh, compared with an average daily transmission loss of 16.3 GWh.

Data from the last three years is averaged to give geographical generation distributions for each settlement period over the course of a year. Generator outages notified to National Grid under Grid Code OC2 (as of 25 Sep 2008) are then applied to the average data to produce a forecast half hourly generation disposition for 2009/10. Only generator outages greater than one month, and over 400 MW are considered. Generation is assumed to be replaced in the central and eastern zone (T_{5,7}).

The base forecast produced by this model is a transmission loss in 2009/10 of 5.82TWh.

Running the model 1000 times with random perturbations to the zonal generation gives an average TL of 5.84TWh, with a standard deviation of 0.15 TWh.

The generation data is based on average outputs for financial years 05/06, 06/07 and 07/08. Scottish wind generation has been increasing over this period, and will increase significantly more in the next year. Scottish wind will rise to 2383 MW in 09/10. Assuming this to be 1500 MW more than the average wind generation over 05/06 to 07/08 and assuming a 30% load factor, then 450MW of additional generation has been moved in the model from central England to Northern Scotland

to allow for this wind effect. This gives an additional 0.16 TWh of losses, increasing the central estimate of transmission losses for 09/10 to 6.0 TWh.

Resistive transmission losses in a current carrying conductor can be described by Ohm's Law as equal to the square of the current flowing in the conductor multiplied by the resistance of the conductor. In order to model this physical process, the transmission loss model incorporates terms including the square of the current. As the square of a negative number is a positive number, this means that in a statistical model where some values can be positive or negative, square terms will increase the positive outcomes and decrease the magnitude of the negative outcomes. The effect of this is to introduce a skew to the distribution of possible outcomes, meaning that the model gives a higher probability of an extremely high outcome above an extremely low one. For example, the probability of a TL of 0.5 TWh above average is approximately three times the probability of a TL 0.5 TWh below average.

In view of this skewed distribution, the forecast transmission loss for 2009/10 is 6.0TWh. A standard deviation of 0.15 TWh gives P10 and P90 values (for a normal distribution) of 5.8 TWh and 6.2 TWh.

Within the BSIS scheme, the difference between the forecast transmission losses and the actual transmission losses is multiplied by a Transmission Loss Reference Price to determine a cost / profit which is added to the total Incentivised Balancing Costs forecast within this document. It is assumed that we have forecast transmission losses correctly, and so the outcome transmission losses are equal to the forecast losses. Our BSIS forecast therefore assumes a £0 outcome from the transmission loss component of the scheme.

4.11 Impact of EU directive for Congestion Management on Interconnection to the GB Electricity Transmission System

4.11.1 The Present Situation

In the current market, capacity on the England-France electricity interconnector is offered for sale via auctions for different contractual periods. This capacity can be utilised or can be traded in a secondary market but there is no obligation to do so.

At present National Grid Electricity Transmission (NGET), as GB system operator, has a number of tools by which it can manage flows on the England-France electricity interconnector for constraint management and energy balancing purposes. These include:

- Trading with holders of capacity on the interconnector to increase or reduce nominated flows dependent on requirements;
- The ability, to limit capacity changes to day ahead nominations on the interconnector by setting and applying Intraday Limits (ITL); and
- Post GB gate-closure, utilising a non-firm Ancillary Service agreed with RTE.

At 16:00hrs day ahead a Mid Channel Reference Point (MCRP) is established by summing the nominations by interconnector users (i.e. the flow on the interconnector for the next day), and following this, the two Transmission System Operators (TSOs) can set an upper and lower limit to which further future nominations by interconnector capacity holders can be changed. These ITLs, offer National Grid and RTE a mechanism to constrain flows on the interconnector .

In addition to these intraday limits, National Grid can also trade with holders of capacity on the interconnector to change the flows outside the intraday limit. These trades with National Grid means that users cannot sell their interconnector capacity on the secondary market and, in the absence of a formal UIoLI mechanism, the capacity is sterilised by the trade.

Post GB gate closure, National Grid and RTE utilise an Ancillary Service Contract to manage interconnector flows (known as the Constraint Management and Balancing CM&B). This service allows National Grid and RTE to vary the transfer of Active Power up to a pre-agreed level of 500MW post GB gate closure. This is a non-firm service.

To manage security issues that may occur post GB gate closure, an Emergency Assistance and Intertrip service is also in place with RTE.

These services are based on reciprocity and the price paid is based on the energy utilised under any service. These services may be withdrawn by either party at any time. It is assumed that these CM&B and emergency assistance services will remain under the CMGs as they are post GB gate closure services.

4.11.2 The Congestion Management Guidelines (CMGs)

Commission Decision^h of 9th November 2006 sets out binding guidelines for the management and allocation of capacity on interconnectors between national transmission systems. The CMGs primary purpose is to maximise the utilisation of capacity of interconnectors and the redistribution of unused capacity with the interconnector fully flowing in the direction of any arbitrage opportunity within day.

Analysis carried out jointly by RTE and National Grid Interconnectors Limited (NGIL) as part of the France-UK-Ireland Electricity Regional Initiative has indicated that the present method of capacity management undertaken by the SO does not fully comply with the CMGs.

To comply with the CMGs a number of changes are planned to be implemented on the sale of interconnector capacity from summer 2009. These include a market-based Intraday allocation mechanism (auctions), Use It or Lose/Sell It (UIoLI/UIoSI) provisions and netting.

It is worth noting that the interpretation of the CMGs by European regulators has been more onerous than originally anticipated.

4.11.3 Impact on the System Operator

The introduction of market-based intraday allocation from summer 2009 will permit IFA Users to buy capacity within day. Our understanding is that the present pre GB gate closure ITL mechanism operated by NGET and RTE would limit the capacity offered within day and therefore would not comply with the Guideline and therefore will be removed.

^h COMMISSION DECISION of 9 November 2006 amending the Annex to Regulation (EC) No 1228/2003 on conditions for access to the network for cross-border exchanges in electricity

In addition, the introduction of UoLI/UoSI rules will remove the ability to trade on the interconnector pre GB gate closure as the purpose of the trade, from a system operator perspective, is to alter flows on the interconnector and, with the new guidelines, this is not possible. For example, currently if a counterparty is exporting to France then National Grid could trade with them to bring their position back to float. However, under the new rules, this would prove ineffectual as subsequently the capacity that they would not be using, post trade, would have to be offered back to the market with the potential that another counterparty could use the capacity to flow to France.

The changes to the sale of interconnector capacity from summer 2009 will also increase the likelihood of flow changes within day from one settlement period to the next from full import to full export, or vice versa (a 4,000MW load change for IFA).

Though it is assumed for system security purposes that a commercial mechanism can be made available to alter flows on the interconnector, it is our interpretation of the rules that all other commercial options will need to be considered prior to utilising the interconnector, regardless of cost (e.g. run oil units in the south-east to secure the system).

Whilst post GB gateclosure, National Grid can utilise the Ancillary Service Contract with RTE to manage interconnector flows, the contract does not guarantee service provision (i.e. non-firm). Our experience and expectation is that the costs are likely to be significantly higher than any pre-gate closure action. Furthermore, under the process currently being drawn up by RTE for cross border balancing, we will be competing on "first come first serve basis" for a limited amount of reserve from RTE, which currently is offered on reciprocal bi-lateral basis.

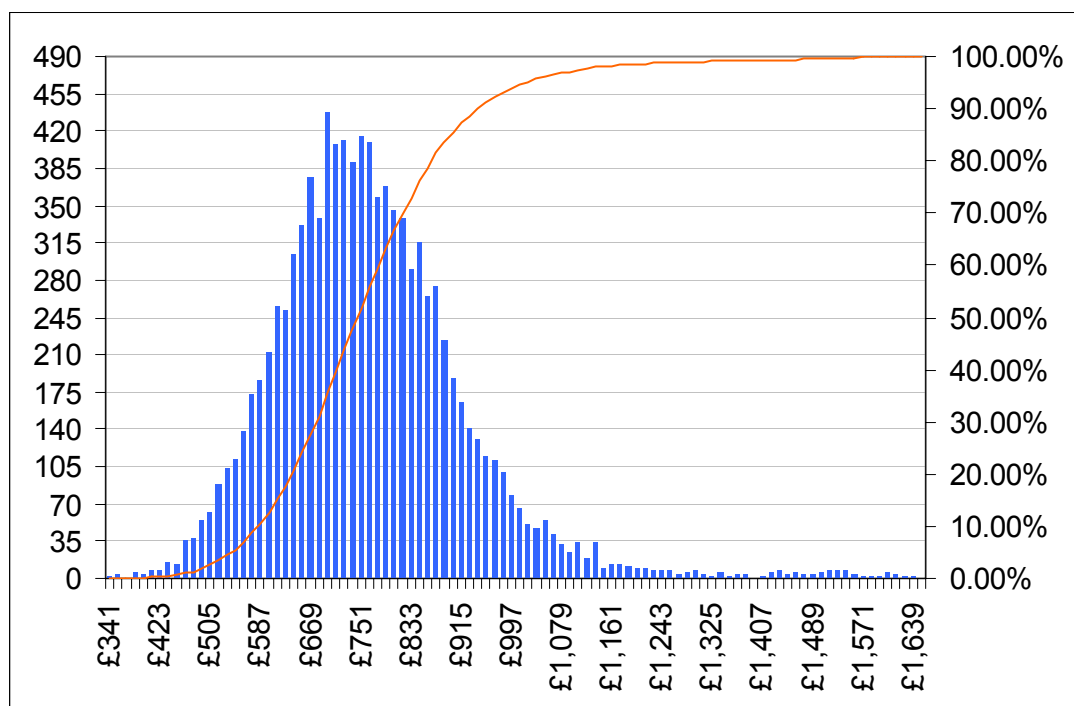
Without the facility of ITLs, but more specifically the ability to trade, the cost exposure to the GB System Operator is expected to be £20m in 2009/10 BSIS year. This is based on considering known outages in England and Wales where the constraints model currently assumes that the constraint would be managed via the French interconnector, and calculating the cost to manage the same constraints using oil generation instead.

This cost estimate is very sensitive to interconnector flows and generation patterns more generally in southern GB. For example, this summer, the French Interconnector has been flowing into GB for the majority of the time and hence constraint costs in southern England have been very low. In previous years we have observed high flows to France which has resulted in considerable trading in order to manage constraints.

5. Incentive Cost Range

As described in the forecast sections above, there are a number of uncertainties when considering the forecast for each incentive component and for the complete incentive costs.

The graph below indicates incentive cost risk / uncertainty profile based on using New NIA



P10 = £583m P90 = £943m

There are a number of uncertainties that remain for 2009/10 balancing costs. With approximately four months of the 2008/09 incentive year remaining at the time of writing, the range of likely balancing costs for 2009/10 remains large at between approximately £583m and £943m using New NIA. This range is due to uncertainties for a number of factors, including:

- wholesale market prices for gas and electricity;
- market length, NIV;
- generation availability and plant margin;
- winter weather and demand levels;
- market shocks, such as a cold snap, plant or infrastructure failure
- volumes of service providers

6. Comparison of 2008/09 and 2009/10 Forecast

The table below compares the baseline forecast incentive costs for 2009/10 with the forecast outturn costs for 2008/9. The comparisons are based on a like for like basis using the proposed modification to NIA, New NIA, discussed above.

All Categories £m	2008/09 Final Forecast (Jan 08) with New NIA	2008/09 Current Forecast Outturn with New NIA	Difference 2008/09 Outturn- Forecast	2009/10 Initial Forecast with New NIA	Difference 2009/10 Initial forecast - 2008/09 Forecast Outturn
Net Eng + Margin	-109	-152	-43	12	163
Net Energy	-347	-569	-222	-418	151
Energy Imbalance	42	-25	-67	-16	9
New NIA	-389	-544	-155	-402	142
Margin	238	417	179	430	12
STOR	65	74	9	93	19
Operating Reserve	153	323	170	314	-9
BM Start-up	20	20	0	23	3
Constraints	124	194	69	307	114
CST - Cheviot	70	125	55	161	36
CST - Scot.Int	35	44	9	81	37
CST - Eng.Wales	19	24	5	65	41
Footroom	4	8	4	7	-1
Fast Reserve	60	60	0	69	9
Response	145	226	81	216	-10
Reactive	63	62	-1	83	20
Blackstart	17	18	1	21	3
Unclassified BM	9	15	6	18	3
TLA	0	0	0	0	0
BM+AS General	4	-1	-5	3	4
Reconciliation	0	2	2	0	-2
LCPD	15				
WIND	10				
UIOLI				21	21
Total	342	432	90	757	325

In the Difference columns in the above table, an orange background indicates an increase (positive difference) of more than £5m, and a green background indicates a decrease (negative difference) of more than £5m magnitude. Further, only values in bold are summated to give the total. Values in grey are sub-component values or sub-totals: Net Energy is the sum of Energy Imbalance and New NIA; Margin is the sum of STOR, Operating Reserve and BM Start-up; Net Eng + Margin is the resultant sum of Net Energy and Margin; Constraints is the sum of CST – Cheviot, CST – Scot int and CST – Eng Wales.

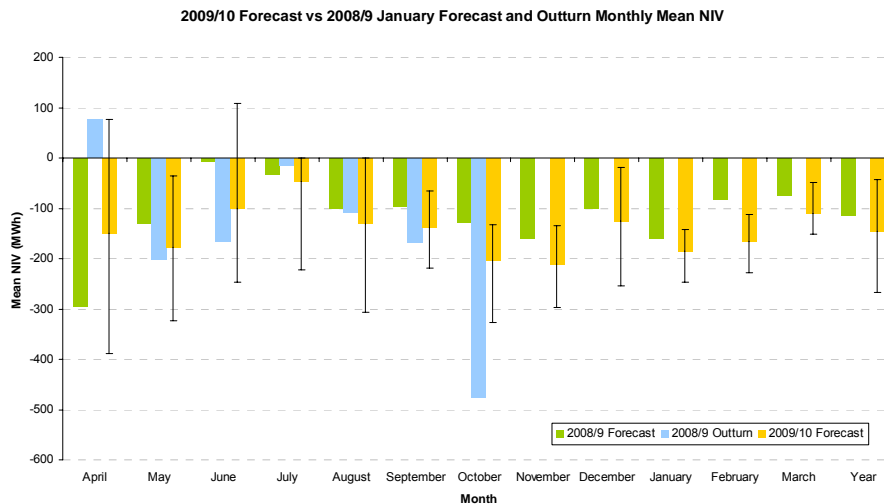
Traditional NIA was forecast to be -£196m in 2008/09, and is forecast to outturn at -£206. Traditional NIA for 2009/10 is forecast to be -£167m. This gives total IBC forecasts of £535m, £770m and £991m respectively.

The major areas of change from 2008/09 are Net Energy, Margin, and Constraints. These are interdependent, and are linked from the volume and price forecasts.

6.1 Volume Increases

The volume forecast within the 2009/10 Energy Model (and subsequently other components with a NIV input in the 2009/10 forecast) is based on historic outturn market lengths from April 2003 to September 2008. This was then weighted towards more recent years in a ratio of 4:3:2:1. In contrast, the 2008/9 forecast (produced in January 2008) was influenced by the exceptionally short summer which had been experienced during 2007; there was no way of knowing if this would repeat in 2008.

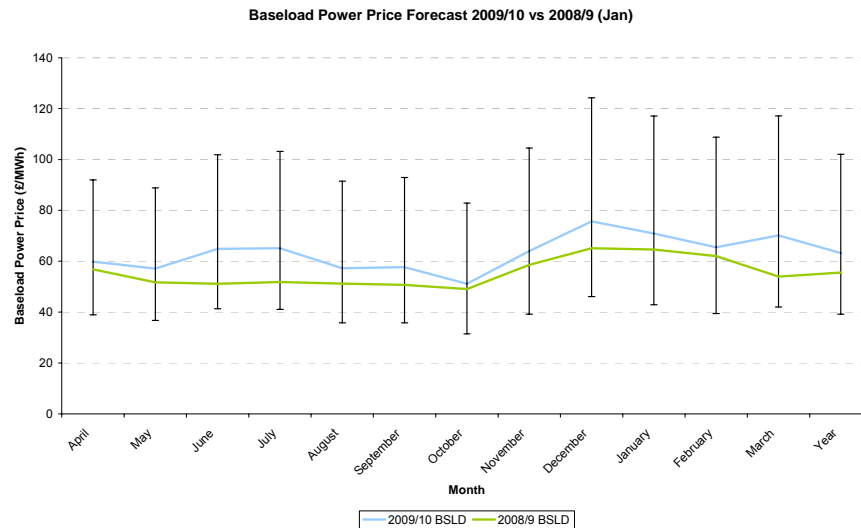
The graph below shows the forecast mean market length (NIV) from the 2008/9 forecast produced in January 2008 against the outturn since April 2008 and the Central case from the 2009/10 forecast. The range indicators on the 2009/10 data show where the “Long” and “Short” scenarios lie in relation to the Central Case.



As can be seen, the 2009/10 Central Case mean is predominantly longer in every month than forecast for 2008/9. This reflects the experience of 2008/9 – as shown by the outturns – with the forecast market length becoming a little longer on average than in previous years.

6.2 Price

The graph below compares baseload power prices used in the 2008/9 January forecast to those used in the 2009/10 forecast. Once again, the range indicators on the 2009/10 data indicate the extent of the prices used in the newly added scenarios. These prices are based on current forward prices as published in Argus.

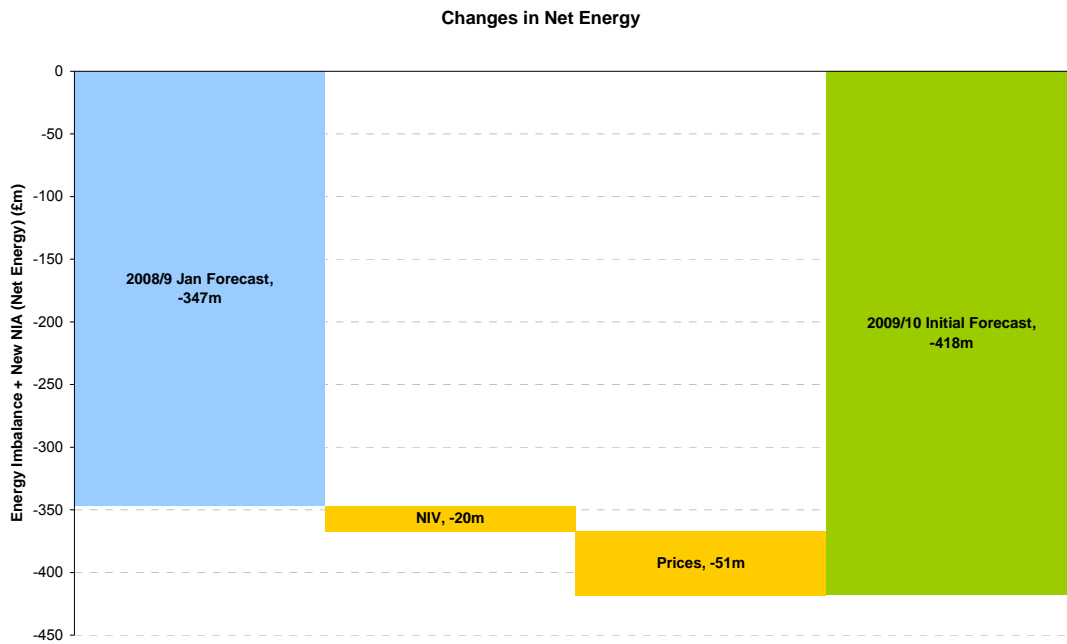


As can be seen, the Baseload prices are broadly similar between the two forecasts although there is a slight increase between the two years. This increase is approximately £8/MWh or 14% over the year (Argus forward prices for 2008/09 on 21 Jan 08, average £55.55/MWh, compared to Argus forward prices for 2009/10 on 17 Oct 08, average £63.26/MWh.)

The scenarios for prices used in the 2009/10 forecast are based on analysis of the ranges of outturn prices compared to forward prices at different lead times. The input prices are taken from the range 60 – 160% of the forward prices, although this reduces closer to real time. This represents a P10 to P90 range. In other words, prices would be expected to appear in this range 80% of the time assuming historic patterns remain unchanged.

6.3 Net Energy

As we have seen, the overall energy forecast is for a slightly longer market length combined with slightly higher prices compared with the January forecast for 2008/09. The combined effect of these is to marginally increase the net income from the combination of NIA and Energy Imbalance costs. This results in the Central Net Energy Forecast coming out at £-418m compared to £-347m in the January forecast for 2008/9.



The chart above demonstrates the steps between the January 2008/9 forecast and the initial 2009/10 forecast with the contributions of prices changes and market length changes shown in orange between the two.

6.4 Operating Reserve

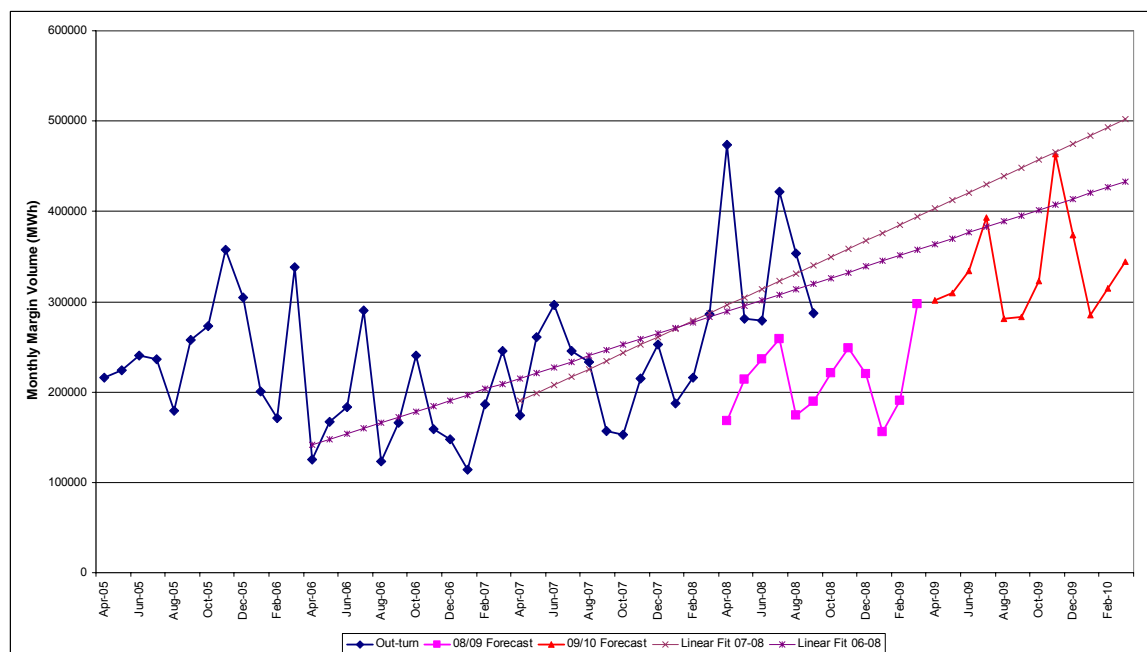
This is forecast to increase by £161m from the final 2008/09 BSIS forecast of £153m to the initial 2009/10 forecast of £314m. This is a £9m decrease from current forecast out-turn for 08/09.

As noted above, there is a price increase of 14% from final 2008/09 forecast, from £55.55/MWh to £63.26/MWh.

There is a volume increase of 1.4TWh from final 2008/09 forecast, from 2.6TWh at final 2008/09 forecast to 4.0TWh for the initial 09/10 forecast. Outturn for 2008/09 from April to end of September is 2.4TWh, with a forecast out-turn for 2008/09 of 4.3TWh. The decrease between 2008/09 current forecast to 2009/10 initial forecast is due to increased use of static providers and an increase in market length. However, this decrease in volume is offset by increases due to reduced availability of LCPD and nuclear plant and increased wind generation.

The volume forecast is presented below, showing out-turn monthly margin volumes since BETTA go live, together with the 2008/09 and 2009/10 forecasts. Linear extrapolations of out-turn volumes from Apr 07 to date and from Apr 08 to date are also shown.

HISTORIC AND FORECAST MARGIN VOLUME

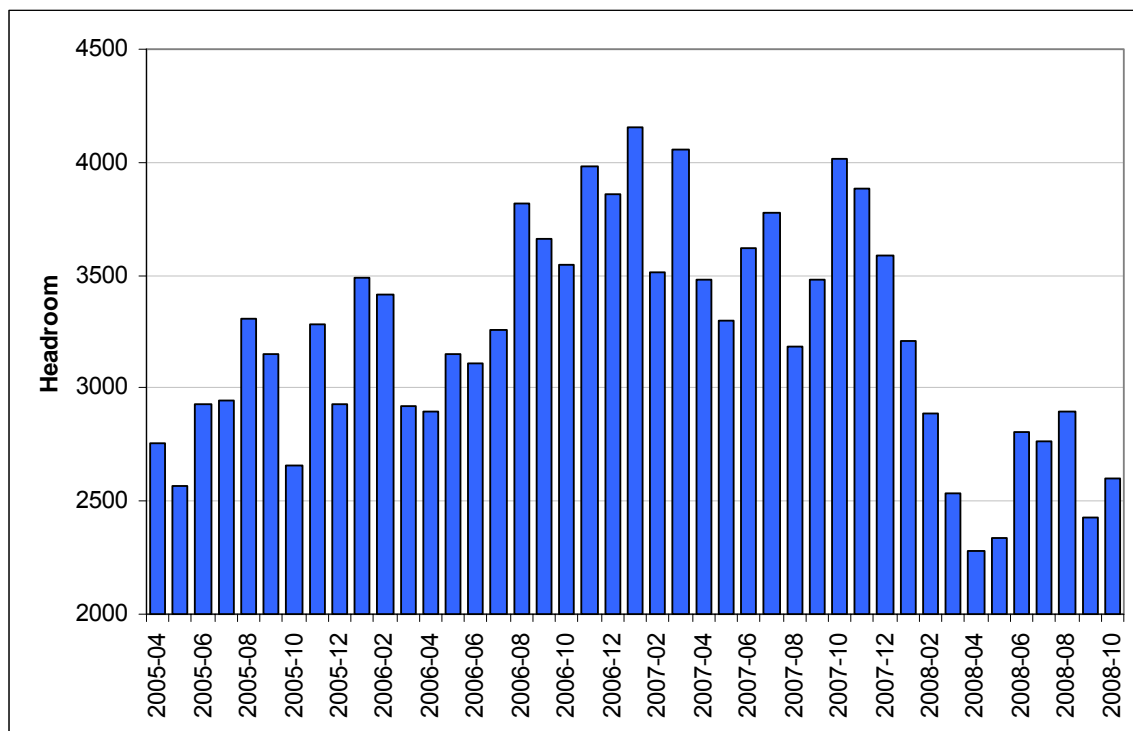


Volumes of margin actions required by National Grid have risen in 2008/09 primarily due to:

- Reduced use of static service providers
- Reduced base load nuclear availability reducing the margin inherent on the system.
- LCPD, with LCPD plant tending to operate as larger units defined by their chimney stacks rather than as individual generators and tending to operate at full load, as their running hours are calculated regardless of whether the generator is running at full or part load. The loss of smaller individual generators running at part load has reduced the margin inherent on the system, and so increased the volume of margin that National Grid has to procure.
- Market length. Net imbalance volume has on average been shorter, reducing the amount of margin provided to the system by market length, and so increasing the volume of margin that National Grid has to procure.

For 2009/10, National Grid anticipates making greater use of static service providers, and expects market length to increase, thus reducing margin volume required to be procured by National Grid. This is offset by assuming a continuation of the within year reduced nuclear availability and LCPD effects that occurred in 2008/09.

The loss of margin inherent on the system in 2008/09 is illustrated in the graph below which shows the difference between the sum of Maximum Export Levels (MELs) at gate closure (where FPN>0) and the sum of FPNs.



Even though the step change in headroom is clearly visible for 2008/09, by using an assumption which heavily weights 2008/09 but also includes weightings for headroom from 2007/08, 2006/07 and 2005/06, the margin forecast for 2009/10 is likely to be conservative.

6.5 England and Wales Constraints

Prices of the required actions are taken from the margin forecast along with the price of the alternative action that would have been taken were the constraint not active from the energy forecast. The actions that would have been taken depend on whether the market is short or long, and whether there is adequate margin on the system.

In the following explanation, volumes are assumed to be positive, and so a positive bid represents an income to National Grid.

With Margin Long, Energy Long, then the only action is to take a bid on a unit in the constrained area, and the cost is the difference between the best bid price available on the system and the constrained bid price that had to be taken in stead. Our analysis shows that this situation occurs 14% of the time.

With Margin Long, Energy Short, then a bid has to be taken on a unit in the constrained area, and the energy must be replaced by taking an offer on a unit outside the constrained area, the cost is then the difference between the best offer price available on the system and the constrained bid price also taken. Our analysis shows that this occurs 3% of the time

With Margin Short, Energy Long, the energy cost is calculated as above, but it is also necessary to replace the margin lost by the constraint which is calculated as the average cost of margin, as defined in the margin model, less the best available bid price outside the constraint. Our analysis shows that this occurs 39% of the time.

With Margin Short, Energy Short, the energy cost is as above, and the margin replacement cost is the difference between the average margin replacement cost and the best offer price available. Our analysis shows that this occurs 44% of the time.

The 'out of the money' cost of resolving a constraint is then modelled as a time weighted average of the four costs detailed above.

The initial forecast for 2009/10 is £65m, compared to a final forecast for 2008/09 of £19m, and a current forecast out turn for 2008/09 of £24m

Constraints are determined by system outages, which vary year on year depending on system requirements and customer requirements such as new connections. Outage costs can therefore be expected to vary significantly year on year.

For the initial 2009/10 forecast, some 50% of the cost is allocated against a single set of construction works associated with the connection of new generation.

In addition, general costs are likely to be higher next year as southern LCPD plant is anticipated to run at reduced load. Also, forward prices, together with changes on the operation of the French Interconnector, both suggest reduced imports from France. Both of these effects increase natural flows from North to South which increase volumes of constraints.

It is assumed that Marchwood and Langage will commission next year, and the presence of these generators is considered as possible mitigation for relevant transmission outages.

6.6 Scottish Constraints

This section covers both Cheviot and within Scotland constraints.

Prices of the required actions are calculated as for England and Wales constraints.

No allowance for changes to the outage plan (such as outage over-runs) was built into the 08/09 forecast and there is currently no allowance in the 09/10 forecast.

The Scottish Constraint forecasts are currently indicative and are subject to change following receipt of final outage plans due from the Scottish TOs in week 49.

	Final 2008/09 Forecast	Current forecast 2008/09 Outturn	Initial 2009/10 Forecast
Cheviot Costs (£m)	70	125	161
Cheviot Volume (TWh)	1.29	2.32	2.43
Internal Scottish Costs (£m)	35	44	81
Internal Scottish Volumes (TWh)	0.98	0.76	1.07

Cheviot export constraints can be resolved by: system to generator intertrips; actions in the BM; forward trades; or constraint management contracts. The spreads seen in Scotland tend to be larger than those seen in England and Wales as the constrained off generation is likely to be cheaper than the marginal generation cost.

For a significant percentage of the Cheviot outages this summer, it is not yet clear whether Northern Scottish generation will be constrained by internal Scottish constraints or will reach the Cheviot boundary. Much of the new wind is located further north than existing generation. This means that Scottish internal constraints are likely to need to be resolved ahead of Cheviot constraints, as the extra new power will not be able to get as far as Cheviot. As a result, the constraints will have to be resolved by actions in the BM, forward trades or constraint management contracts rather than using Cheviot intertrips.

Another factor leading to increased costs is the volume of work requiring a number of outages being planned after clock change in the autumn, when prices are higher.

7. Conclusion

Our overall central forecast for incentive scheme costs for 2009/10 is £757m, based on the modification to NIA (New NIA) discussed above. This compares on a like for like basis with a forecast outturn for 2008/09 of £432m, and the forecast for 2008/09 of £342m.

On the basis of traditional NIA, the 2008/09 forecast was £535m, and current forecast out turn is £770m.

Understanding the increase between the forecast for 2008/9 and 2009/10 requires that we look at the unanticipated drivers experienced within 2008/9.

These increases have been a result of:

- Outturn wholesale power price increases from circa £55/MWh (March) to £100/MWh (September)
- Longer than indicated outages and higher than forecast volumes of pull-back required against Scottish constraints
- Outages of key circuits and static reserve providers
- Reduction in free headroom due to LCPD and reduced nuclear availability

The latter two of these have seen a requirement to synchronise more units to provide margin which has in turn pushed up the replacement costs for constraints.

Moving from the current forecast position for 2008/9 to the initial forecast for 2009/10, we see:

- A continued reduction in static response provision, leading to an increase in margin actions and dynamic response holding when compared to the final forecast for 2008/09.
- Changes to access to capacity on the French interconnector (“Use It or Lose it”) likely to lead to a significant increase in balancing costs
- A higher volume of planned outages of key English North – South circuits than has been required in recent years, likely to lead to significant costs.
- Continuing high price spreads between bids to manage Scottish constraints and replacement offers in England and Wales
- Additional wind generation connecting above Scottish / Cheviot constraint boundaries

There is significant risk associated with the potential outturn costs. In producing the forecast, there are a number of assumptions that affect the forecast costs. These assumptions are likely to change prior to the start of the scheme for the scheme duration. One such assumption is power price. This directly affects a number of component costs (e.g. reactive) and interacts with others (e.g. reserve costs). In addition, the number of outage weeks across significant constraint boundaries will have an effect on the constraint costs. The current forecast outlines the best information that we have at this time. However, these assumptions are changing and we will have a more detailed understanding of the likely out come after the winter.

Annex A - Impact of Additional Wind Capacity on Balancing Costs

Introduction

This note describes in more detail our forecast of balancing costs associated with wind generation for 2009/10. We have identified the growth in wind generation as a cost driver as part of our review of the longer term drivers of balancing costs. There is a significant volume of wind generation planned to connect to the system over the next 5 years. The level of cost impact on our residual balancing activity that will result from this growth is uncertain and will depend on the level to which market participants are able to manage their own positions.

This note provides details of the impact of the increase in wind generation on the system operating costs for 2009/10 associated with Reserve and Dynamic Frequency Response, comparing this to the current costs and predicted costs in future years.

Summary

Our central forecast cost of wind generation for 2009/10 is £184m. This consists of the following breakdown:

- An increase in the volume of constraint actions with a cost of £164m
- An increase in the volume of reserve required at 4-hour ahead of £17m
- Increase in the volume of dynamic response and fast reserve with a combined cost of £2.5m
- We assume participants will manage all variations in output beyond the four hour stage, therefore we forecast no immediate increase in reserve beyond the 4-hour ahead timeframe.
- Increase in Downward Regulation costs £150k

Our forecast is based on our best view, based on market intelligence and internal data, of what generation is likely to actually connect and generate in 2009/10. In the event that Interim Connect and Manage, or SO release of short term TEC, is implemented during 2009/10 as part of the Transmission Access review, then it is possible that the wind generation volume may rise to this higher figure, with a consequential increase in costs associated with wind generation.

Analysis of Intermittency of Wind

There are significant daily and seasonal factors that affect wind load factor. Figures 1 & 2 below show the mean load factor and standard deviation for the wind generation that we currently meter. Wind generation outages are included in the data. Numbers quoted are as a percentage of installed capacity.

Figure 1: Mean Load Factor of GB wind

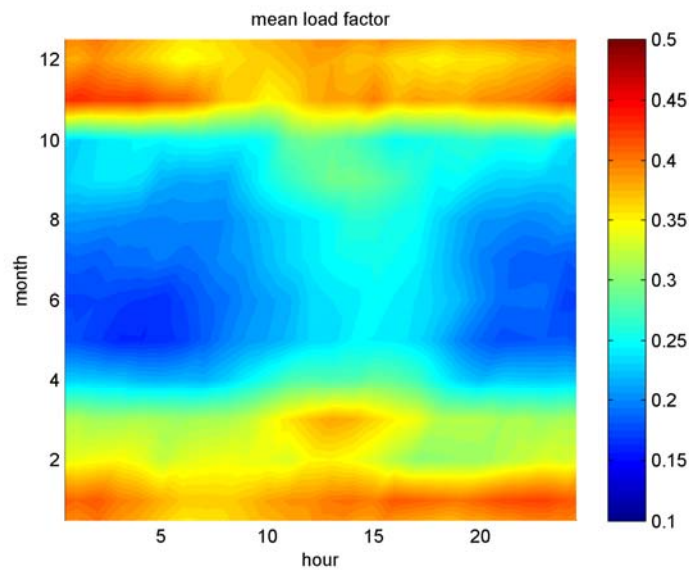
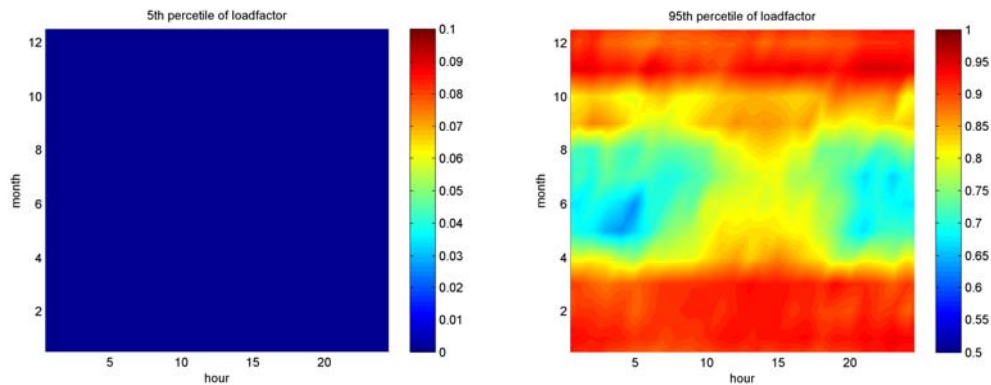


Figure 2: 1 in 20 Load Factors of GB wind



The main points from Figures 1 & 2 are:

Across the winter

- Average load factor is around 35%-40% (November to March inclusive).
- Wind load factors are higher than during the summer due to more wind and less station outages.
- The wind load factor on any given day during the winter can be any value.
- The wind load factor is the same overnight as during the day.

Across the summer

- Average load factor is around 20%-25%.
- Average load factors drop to around 17% overnight.
- Outages are mainly taken in the summer and hence effect the load factor calculation.
- The volatility of wind load factors over the summer is lower than the winter, and are at the lowest overnight.

Impact on Constraints

As most of the wind farms are connected within Scotland they are behind (at least) the Cheviot constraint. Consequently the output of these windfarms has a direct effect on the constraint forecast.

One can easily estimate the constraint cost caused by wind by simply setting the expected wind output within the Scottish constraint models to zero, and then comparing the model output with the original constraint cost forecast.

For 2009/10, the cost of wind generation on constraint spend is estimated to be £148m.

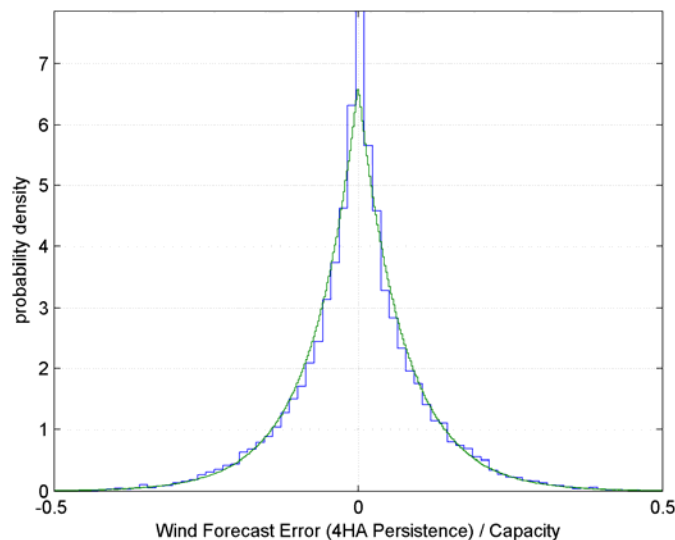
Impact on Reserve Requirements

Our Reserve requirements are set such that the loss of load expectation is set to 1 in 365, or one event per year. Our reserve requirements are calculated using the historic level of demand forecast error and generation plant reliability, which approximate to a normal distribution.

We have analysed the impact of wind on reserve. Figure 3 below shows the distribution of wind forecast error. The blue line represents the observed data, while the green line represents the best fit that we use when modelling wind.

It is possible calculate the extra cost of wind on Reserve by calculating Short Term Operating Reserve Levels with and without wind, subtracting one from the other to get the net effect.

Figure 3 The Distribution of Wind Forecast Error



As more and more wind connects we expect this distribution to remain stable, therefore we expect the reserve level, in MW, to rise in line with increasing wind capacity.

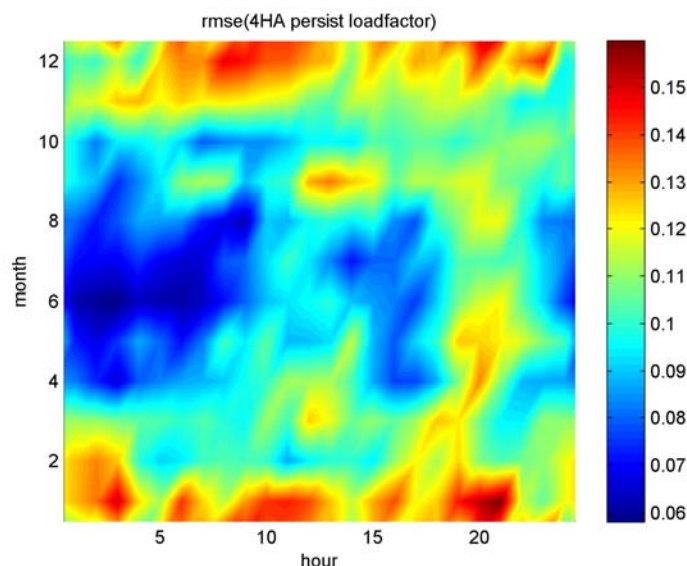
Considering the potential increase in reserve requirements and the cost of reserve procurement, we forecast a range of costs from £12m to £25m in 2009/10.

We have taken care to avoid raising the reserve requirement during those times when the wind output is behind an active constraint. In those cases any volatility in the wind output influences the constraint requirement (and therefore constraint costs), but not the reserve requirement.

Frequency Response and Fast Reserve Costs

The Root Mean Square Error (RMSE) is not constant across the year and the picture below shows where the greatest errors reside using a persistence based modelling technique.

Figure 4: RMSE of GB wind



The greatest errors occur around sunrise / sunset across the spring / summer. These errors correspond to where the Reserve Requirement, Fast Reserve Requirement and Dynamic Response Requirement are at their highest.

At this stage, and level of wind generation, we do not think that dynamic response or fast reserve levels will have to increase at all times of the day.

However there will be a number of days across the year where the variability of wind, under high wind output conditions, results in frequency control becoming more difficult to control. When these conditions arise we increase the level of dynamic frequency response held to assist in managing the frequency variation to within limits.

With increasing wind the variability of generation will lead to other forms of reserve being required to cover shortfalls. Fast Reserve covers the intermediate timescale between synchronised reserve and other forms of longer notice reserve such as STOR.

Our forecast assumes that we require additional response and fast reserve on high wind output days, the combined cost of this is estimated to be £2.5m, which is included in the response forecast.

Downward Regulation costs

As a result of ROC incentives to maximise output, wind-powered generation is expected to submit unattractive negative Bid prices. Therefore during the summer low demand periods, wind generation output will increase the costs of maintaining our downward reserve requirement either directly through pricing or more likely indirectly through the displacement of alternative generation with more attractive bid prices.

Figure 1 shows that overnight during the summer, the average load factor of wind generation is around 17%. Therefore with an additional 800MW of wind capacity for 2009/10 will on average result in an additional 140MWs of inflexible generation.

The downward regulation cost estimate is £150k. This low figure confirms our view that levels of wind generation are not significant enough to impact on downward regulation requirements. However, it should be noted that this issue may become more prevalent in future years as the level of wind output rises and will be kept under review.