

Malcolm Arthur
National Grid
National Grid House
Warwick Technology Park
Gallows Hill
Warwick
CV34 6DA

3rd October 2008

Dear Malcolm

NATIONAL GRID SYSTEM OPERATOR INCENTIVES – CONSULTATION ON THE DEVELOPMENT OF AN INCENTIVE TARGET INDEXATION METHODOLOGY

Thank you for the opportunity to comment on the issues raised in your consultation on the above as published on 4th September 2008.

Headlines:

- **We agree in principle that where elements of costs are not directly influenceable by the System Operator and can be identified, the incentivised costs should be adjusted. This allows the incentive to be focussed on those costs which the System Operator can optimise.**
- **The System Operator has more information and expertise in forecasting future costs than most participants, including forecasts of costs over which it has no direct influence. Therefore we think it appropriate that some incentive effectively remains on the SO to attempt to forecast total costs accurately.**
- **While supportive in principle of the unbundling of costs into individual incentivised components, we see great difficulty in doing this accurately without better objective tools for doing so, particularly given that costs of many activities overlap**
- **The cost of constraints depends on many variables, some of which are directly influenceable by the SO. There is currently insufficient information to justify removing these costs from the incentivised targets.**
- **We support in principle a longer term incentive scheme, however, we see difficulty in devising such a scheme without better objective tools to distinguish the costs which are directly influenceable by the System Operator and those which are not.**

British Energy Group plc
Barnett Way
Barnwood
Gloucester GL4 3RS

T +44 (0)1452 652222
F +44 (0)1452 653775
www.british-energy.com

Registered Office:
GSO Business Park,
East Kilbride G74 5PG
Registered in Scotland No. 270184

General Comments:

We agree in principle that where elements of costs are not directly influenceable by the System Operator and can be identified, the incentivised costs should be adjusted. This allows the incentive to be focussed on those costs which the System Operator can optimise.

However, we also think the System Operator has more information and expertise in forecasting future costs than most participants, including forecasts of costs over which it has no direct influence. Therefore we think it appropriate that some incentive effectively remains on the SO to attempt to forecast total costs accurately.

An 'index' of 'uninfluenceable' costs based on historic correlation with short term market prices and imbalance volumes provides one method of determining an adjustment to incentivised costs. We are comfortable with this method, subject to detailed comments given below, provided the historic correlation remains valid in the face of changing market conditions and behaviours. A proposed index on energy, reserve, downward regulation and fast reserve costs (but not frequency response, constraints or reactive power) meets this requirement reasonably well over recent years. If such an index were to be adopted, careful monitoring of validity from year to year would be required.

An index of the form proposed (excluding frequency response) appears to give a better representation of 'uninfluenceable' costs than the current NIA approach.

While supportive in principle of unbundling of costs into individual incentivised components, we see great difficulty in doing this accurately without better objective tools for doing so, particularly given that costs of many activities overlap. Nevertheless, we support transparency of whatever data the System Operator has on itemised costs, which helps inform participants own forecasts of balancing costs and may promote suggestions for future improvements in efficient balancing. The analysis in this consultation provides useful information on balancing costs, even though much of the analysis may not be explicitly included in a final incentive scheme.

While supportive in principle of a longer term incentive scheme, we see difficulty in devising such a scheme without better objective tools to distinguish the costs which are directly influenceable by the System Operator and those which are not. Any longer term incentive scheme should be developed hand in hand and not without tools to allow relevant performance to be objectively and reliably measured. Itemisation and incentivisation of individual components of costs could be used if suitable transparent models were available to measure the success of optimisation by the SO. This could be expensive, and much more work and information would be required to confirm a net cost-benefit. If a longer term incentive scheme were to be considered on the basis of historical correlations such as described in this consultation, there would have to be allowable adjustments to cover the variation of these correlations during the scheme period.

Response to Specific Questions

Question 1 – Do you agree with the principle of indexation?

Yes in principle, where those elements of costs which are not directly influenceable by the System Operator can be practically identified. The System Operator has more information than most, if not all, users about future market conditions (see for example its winter reports and seven-year statement), and its forecasts should themselves be subject to some form of incentive, even where it cannot directly influence the out-turn costs.

Question 2 – Do you support the use of indexes for the scheme starting in April 2009?

Yes in principle, subject to rational detail.

Question 3 – What incentive components should be included in the indexation methodology?

Energy, Reserve, Downward Regulation, Fast Reserve. Of the other items specifically considered for inclusion, Constraints, Reactive Power and Frequency response should be excluded, at least initially, as their reliability in giving consistent indices is not proven.

Question 4 – Considering the volatility of the index and the individual components, are there any periods that should be excluded from the development of indexation components e.g. exclude the data from 2005/6 due to the market being unsettled in the first year of BETTA?

We agree that 2005/06 should be excluded as a reference period for determination of the index, but think the reason for differences in 2005/06 should be considered further to inform future consideration of potential volatility and hence validity. We remain undecided whether all subsequent years or only more recent year(s) should be considered as the reference. We agree that constraints and reactive power should be excluded from indexing, at least initially, as their reliability in giving consistent indices is not proven.

The frequency response index shows significant season to season and year to year volatility which is not fully explained. It does not appear as reliably consistent as the other included items, and we suggest it should also be excluded, at least initially.

Question 5 – Do you agree with the proposed method of indexing balancing costs?

In principle, we see potential merit in using historic correlation of outturn costs, short term market prices and imbalance volume as reference in determining future incentives. However, there are a number of concerns in detail, described elsewhere in this response, including a concern that frequency response costs do not behave consistently and should not be included in the indexing.

Question 6 – Are there any additional benefits / drawbacks of implementing the proposed indexation?

A benefit is improved transparency of data and assumptions behind it. A possible drawback is that fundamental changes in behaviour could undermine the validity of the index. However, this problem exists with the current NIA adjustment.

Question 7 – Do you have any comments on the development and implementation of an energy indexation?

We are unconvinced of the benefits of creating an index specifically for 'energy balancing'. However, we support transparency in reporting by the SO of those individual components of costs, including what such an index might be if it were to be used. Software tools to model the real physical behaviour of the system and balancing actions could provide an objective measure of System Operator performance relative to theoretical ideals. However, we acknowledge the difficulty in creating such tools.

Question 8 – Do you have any comments on the development and implementation of a reserve index?

It is reassuring that the indexing methodology has delivered an indexation which is dependent on short term market prices but not imbalance volume. This suggests that the SO's identification of

the costs of reserve is reasonably successful. We would expect a valid reserve index to be correlated also with longer term market prices and expectation of imbalance prices. However, in conjunction with the other proposed components of imbalance costs and subject to detailed comments provided below, we think the inclusion of reserve costs in the proposed index should provide more accurate adjustment of incentivised costs.

Question 9 – Do you have any comments on the development of constraint cost indexation? What incentive arrangements should be considered for constraint costs?

We agree that the cost of constraints depends on many variables, some of which are directly influencable by the SO. There is insufficient information to justify removing some of these costs from the incentivised targets. The consultation mentions outage weeks as an important factor in determining constraint costs, and it would be interesting to see a correlation with outages (import/export?) as an independent variable to inform on the importance of this element.

Question 10 – Do you believe that a reactive power index should be developed? What is your preferred option for a reactive power index?

Given the year on year and month on month fluctuations in index parameters, we see no justification or benefit in developing reactive power index in the forms suggested. Reactive power requirements can be very local, and therefore subject to both reactive and active power constraints, which can interact with each other to affect costs. As with frequency response, we see potential value for participants in the SO seeking to identify and make transparent the costs, but for now inclusion in the main incentivised cost seems appropriate.

Question 11 – Do you believe that a frequency response index should be developed? What is your preferred option for a frequency response power index?

Given the year on year and month on month fluctuations in component index parameters, we see no justification or benefit in using a frequency response power index in the same form as the proposed 'energy' index. We acknowledge the interaction between some frequency response costs and BM prices. There may be scope to develop a rational incentive scheme on lines similar to those described in Appendix C, but considerably more work would be required to distinguish those costs which the SO can reasonably predict and/or influence, and those which it cannot.

Question 12 – Do you have any comments on the benefits and drawbacks of unbundling? If any, what incentive components could and should be unbundled?

National Grid has identified many difficulties with unbundling. Additionally, industry is reliant on NG's methods for identifying and publishing interacting costs. We welcome transparency of costs, which helps inform participants own forecasts of those costs, but do not see great benefit in further unbundling of balancing costs at this time.

Question 13 – Are there any other forms of indexation that you believe should be considered further?

Although we are not proposing an explicit incentive on transmission outage periods, it would be interesting and informative for future costs to see the extent of correlation of these with constraint and reactive power costs.

'Question 14 – Do you believe that there are benefits in developing longer term incentives? Are there any benefits or drawbacks not covered by this consultation?'

Any longer term incentive scheme should be developed hand in hand and not without tools to allow relevant performance to be objectively and reliably measured. Itemisation and incentivisation of individual components of costs could be used if suitable transparent models were available to measure the success of optimisation by the SO. This could be expensive, and much more work and information would be required to confirm a net cost-benefit.

Attached is an annex that sets our comments on some of the detail that was published in the consultation paper.

If you have any questions regarding the above please do not hesitate to contact me.

Yours sincerely

A handwritten signature in black ink, appearing to read 'DL', with a stylized flourish underneath.

David Love
Head of Regulation

Direct Line: 01452 653325
Fax: 01452 653246
E-Mail: david.love@british-energy.com

Annex 1 – Detailed Comments:

Paragraph 22 refers to "an increase in the volumes of reserve needing to be procured by National Grid as a result of a more balanced market and lower headroom on plant". This suggests the SO has previously benefited from individual users holding their own energy increase reserve. An unanswered, and possibly unanswerable, question is the most efficient balance between procurement of reserve/balancing by users according to individual requirements and procurement of collective reserve by the SO. We have supported cashout mechanisms which reflect more marginal costs on those in imbalance, in expectation this should lead users to make efficient decisions whether to hold their own reserve to avoid imbalance, or rely on the System Operator.

Figure 1 – Day ahead versus forward power price. 'Analysing the volatility of the forward price against outturn day-ahead price, the average of the outturn day-ahead power prices falls within 60% and 160% of the year ahead Argus index price only two-thirds of the time.'

What is the source and nature of the forward price curve? What is year-ahead Argus index price? The equivalent forecast should be published in consultation for future incentive schemes.

'37. Since the introduction of BETTA, constraint costs have increased significantly as shown in the graph below'

How are constraint costs determined and distinguished?

'43. When considering the price of resolving constraints, the price of replacement energy also needs to be considered. For example, for an export constraint, the volume of energy required to reduce the flows on the boundary and subsequent replacement price need to be considered with the replacement energy required outside the constrained areas to maintain energy balance. The constraint price is then the total of these two prices.'

We assume 'the total of these two prices' means to describe the net cost of the two (or more) opposing actions required to resolve the constraint. The additional cost of the action taken outside the constrained area should be modest unless choice is squeezed by particularly tight margins.

'44. Recent trends have shown an increase in the absolute spread in bid and offer prices....'

This is probably due to increases in costs associated with bringing on unsynchronised generation or desynchronising running generators for balancing purposes.

'54. The final proposal was an indexation level of +£2m change in target for each +£1/MWh change in outturn average annual wholesale price.'

If there is a relationship, but the proposed assumed correlation underestimates the effects of price, then the adjustment to incentive scheme target expose the SO to those effects. Conversely, an overestimated effect will reduce exposure of the SO to costs which are not price related. We prefer to err on the side of underestimation, so that the SO retains incentives related to price, even though it may have limited influence over those prices.

'56. The index adjusted the scheme target by £1.57m for each additional week of outage that occurs, and vice versa. For example, re-basing the 2008/09 incentive scheme forecast of £544m forecast (containing 30 weeks of outages) down to a proposed index base (of 8 weeks) reduced the scheme target by £34.5m.'

It is not clear how the reference target for constraint costs is set. What are the incentives to reduce outages below the planned level? A target of zero would provide incentive to minimise the costs in all situations.

'61. The analysis undertaken by Ofgem is shown in Appendix 85. The analysis showed a strong correlation between the major components of the incentive costs and baseload wholesale prices.'

This statement appears to contradict NG analysis in sections 51 & 52 where poor correlation with price was shown.

3.2 Development of Indexation

A further factor to consider is the System Operators success in forecasting outcomes, even where they have limited ability to influence those outcomes. The system operator has much information and expertise which is not shared by many or perhaps any parties and consumers. For example, if the SO underestimates future prices then parties pricing BSUoS on SO forecasts may lose, and vice versa. If the SO is isolated from the outturn price, it has less incentive to make good forecasts. Retaining some component of incentive on the forecast itself should maintain incentives on the System Operator to make good forecasts.

'77. Figure 6 also indicates that the NIA parameters of 2.5 x power price when the market is short and 0.5 x power price when the market is long still hold true.'

The figure shows that an NIA parameter closer to 2.0 would describe prices since January 2008.

'81. Figure 8 ... It can clearly be seen that subset of balancing costs increases with a market becoming less long.'

It is consistent with expectation that balancing costs increase if the SO has to buy more energy in a short system rather than sell it in a long system.

'86. The following BSIS components were not included in the analysis:

- FFR option fees
- Constraint contract costs and intertrip fees
- STOR option fees
- Fast reserve option fees
- Black start costs
- BM start up costs
- Non-BM STOR utilisation payments'

The costs were excluded from our initial analysis as there is no direct relationship to power price and market length. Generally the costs are associated with contract and option fees that are not readily broken down into half hourly costs. However, the utilisation costs of a number of these services are included in the analysis as these utilisation costs are associated with BM prices e.g. BMU STOR utilisation.'

We consider several of these items may be related to power price and/or market length. For example, the option fees associated with providing energy services will be related to expected energy prices.

90. Figure 9 includes a large number of data points. To rationalise this data, the average Cost/SPNIRP for each value of -TQEI was calculated e.g. all Cost/SPNIRP values from -100.4MWh to 99.5MWh were grouped together, an average value taken and this average value plotted against the -TQEI of -100MWh.

Balancing cost is usually assumed to be a true function of individual volumes and prices in individual periods. The average price in each period can be expressed as cost/net volume. The analysis seeks to approximate the function as an assumed one on net volume TQEI and market APX forward price in individual periods. Instead of correlating the true average price with the proposed market price, the analysis correlates the net volume with Cost/Market Price, the effect of which is probably similar. This gives some correlation. The analysis then makes a further comparison of average cost/market price for each net volume, with the net volume itself. The justification for this step and the regression and correlation which goes with it is not clear. By ignoring the number of points in each TQEI volume 'band', the correlation/regression does not give due weight to each data point and the results will be different. [By eye, it appears that a regression on the points on figure 9 would give a lower slope than those of figure 10.]

'92. This results in a good correlation between (-TQEI) and Costs / SPNIRP over the majority of (-TQEI) values and shows very good correlation over the normal market length operation.'

Method is premised on observation that $(\text{Cost}_j / \text{Market Price}_j)$ is quite well correlated with a function of the form $(a + b \cdot \text{TQEI}_j)$. Using a and b determined from historical half-hourly data and extrapolating forwards to future periods:

$$\text{Cost}_j = \text{Market Price}_j * (a + b \cdot \text{TQEI}_j) = a \cdot \text{Market Price}_j + b \cdot \text{TQEI}_j \cdot \text{Market Price}_j$$

The 'index cost' is no longer a simple multiplier of volume and price. Instead it depends on Market Price itself (with an implicit fixed volume) and an implicit fixed scaling of market price for the net imbalance volume. The physical basis of such a relationship is not clear, which is a concern, although the correlation does appear quite good.

*93. Performing regression analysis, the best fit line (red line) through these points is produced as shown in Figure 11. For comparison, the blue line above shows a plot of NIA. Using the results of the regression analysis, the following relationship with SPNIRP and (-TQEI) is:
Adjustment = 863xSPNIRP + 1xSPNIRPx(-TQEI) + constant'*

A straight line regression of Cost/SPNIRP against TQEI as in figures 9/10 would give a relationship $\text{Cost} = a \cdot \text{constant} \cdot \text{SPNIRP} + b \cdot \text{constant} \cdot \text{TQEI} \cdot \text{SPNIRP}$. Why is the coefficient on $\text{SPNIRP} \cdot \text{TQEI}$ equal to unity (is this rounding), and why is another constant included? All draft proposed values should be described. The number of significant figures used in the 2nd coefficient should be made clear, and should be at least the same as for the first coefficient (3).

We assume this refers to a proposed adjustment to total outturn balancing costs to reflect a component over which the SO should not be incentivised. Paragraph 97 gives an example, with $\text{SPNIRP} = \text{£}50/\text{MWh}$ and $(-\text{TQEI}) = -300\text{MWh}$ (system long) for every period in a year, adjustment of $\text{£}28,150$ for every period, which over the year would be $\sim\text{£}493\text{m}$. By contrast NIA would be $\text{£}7,500$ for every period, and over the year $\sim\text{£}131\text{m}$.

That is, with the system slightly long, NIA would be negative and cause the incentivised cost to be increased. The SO would be assumed to have received $\text{£}131\text{m}$ for spill energy sold cheaply at $0.5 \cdot \text{Market Price}$ to resolve parties underlying imbalance, and that this 'windfall' income would be added to the incentivised cost to give the cost as it would have been without the 'windfall' income. By contrast, with the proposed mechanism, in this same situation, the SO would be assumed to have paid $\text{£}493\text{m}$, a cost derived by historical correlation of cost to net imbalance and market price. In the example given, there would obviously be a huge difference in the incentivised amount.

'94. Using the relationship derived above, this regression has an R2 of 73%7. For comparison, NIA has an R2 of 58%.'

Footnote 7 indicates that the R2 coefficient of determination is derived using the complete data set shown in figure 9. Were the regression values derived from the data in figure 9 (which seems most appropriate) or in figure 10 (which seems less appropriate)?

Figures A3, A4, A5 (and similar elsewhere) represent more than one variable against another, not the usual representation of one variable against another. Regression against more than one variable is possible, but has been avoided by choice of combined variable which appears to give good correlation.

101/Table 3: Are the results referred to the values of 'a' in a relationship of the form $(\text{Cost}/\text{SPNIRP}) = a + (b \cdot \text{TQEI})$? We take 'a' to represent an implied fixed volume (MWh/period) to be priced at SPNIRP in calculation of proposed cost adjustment. If not, what are they? Given the material consequences of their proposed use, the year to year variation is significant.

104/Table 4: As for 101/Table 3, the values shown in the table appear to be implied fixed volumes (MWh/period) to be priced at SPNIRP in calculation of proposed cost adjustment. This only represents the 'fixed' component of the proposed index, not the volume dependent part. Constraints appear to be responsible for a lot of the year to year variation in the data item, which would be consistent with their costs not correlating well with market prices and net imbalance, which is perhaps not unexpected.

108/Table 5 appears to refer to the values of 'b' in a relationship of the form $(\text{Cost}/\text{SPNIRP}) = a + (b \cdot \text{TQEI})$. We take 'b' to represent an implied multiplier on market price SPNIRP to be applied to net imbalance volume in calculation of proposed cost adjustment. Observation of values close to 1 suggests SPNIRP is on average a reasonable estimate of price, except during 2008/09 1Apr-10Jun where the price of balancing per unit of imbalance volume has apparently increased considerably. 110/Table 6 identifies 'frequency response' as the major reason for this, and 'energy' and 'reserve' as secondary reasons.

'111. As expected, the major relationship to $-\text{TQEI} \times \text{SPNIRP}$ is with energy costs. These are the costs associated with resolving energy and therefore are directly related to market length. The relationship with other components is relatively minimal with the majority of the coefficients being at or near zero.'

The costs associated with frequency response appear to have increased significantly from April 2008, but this is not mentioned.

113/114 Table 7/8/9: The tables seem to show significant season to season variation in the proposed coefficients, which call into question the validity of applying them as annual forecast values.

120. It is interesting to note that (a) the SO is able to estimate the cost of constraints and (b) 'the development of contracts and intertrips limit constraint costs and move costs anyway from the BM and trades'. This latter point would presumably cause costs to tend to appear as fixed costs, perhaps dependent on market prices, but independent of imbalance volume. However, year on year change in the observed coefficients suggest a reduction in fixed costs and a reduction in volume dependent costs in a long system, suggesting the 'adjustment costs' for constraints indicated by the correlation have simply disappeared. More explanation of this is required.

124/125/126 Frequency Response. We find it hard to draw conclusions from the data presented, other than that there is considerable fluctuation in the observed correlations with market price and volume from year to year and season to season.

127/Table 15 Reactive Power. Results suggest little correlation between reactive costs and imbalance, as would be expected.

131. [Removing constraints from regression] The result is a more stable coefficient over the period analysed. Therefore it would seem prudent to consider not including constraints in the categories indexed.

Agree, though still not ideal.

'133. The removal of both reactive and constraint costs results in more stable coefficients over the period analysed. If we ignore the first year of BETTA, the index would seem to be very stable.'

The incremental impact of removing reactive power from the index is significantly less than that of removing constraints.

135/Table 18. The incremental impact of removing frequency response from the index is significantly less than that of removing constraints.

137. The stability and volatility of any index implemented will need to be reassessed after this year's winter where power prices and market conditions may be different from previous years.

Agree. Any process which relies on historic data to predict future outcomes statistically is likely to need frequent revision. Further consideration on the relevant 'reference period' should be undertaken.

'138. It is our proposal to implement the most stable index from our analysis. This would include the following components:' [excluding constraints and reactive costs].

The frequency response index does not appear as reliably consistent as the other included items, and we suggest it should also be excluded, at least initially. As above, further consideration of the relevant 'reference period' is required.

'139. The above table indicates that the proposed index is very stable for 2006 – 2008 and shows some variability for 2005/6. As 2005/6 was the first year of BETTA, there is some argument to remove the data when setting the index parameters.'

The noticeable difference in 2005/06 has bearing on the validity of the proposed index and should be investigated further. Perhaps the introduction of P194/205 on 2 November 2006 changed behaviours underlying the proposed index. We are unsure what period should be used as the 'reference' for the proposed index.

140. Are the regression coefficients determined from the raw data or from the 'averaged subset' (see paragraph 90)? We think they should be based on raw data.

144. Has the regression been performed on the raw data or the 'averaged subset' (see paragraph 90)? We think it should be based on raw data, and the final values used will depend on the chosen reference period and components. The number of significant figures used in the 2nd coefficient should be made clear, and should be at least the same as for the first coefficient (3).

149. This refers to overall incentivised costs, not total costs.

150. The first coefficient is different to that in paragraph 144. The number of significant figures used in the 2nd coefficient should be made clear, and should be at least the same as for the first coefficient (3).

151. The adjustment per 1 MWh change in market length will depend on the SPNIRP 'market price'. The cost over the year per 1 MWh change in market length will only be £0.175m if this price is 10 £/MWh. Lower prices would give correspondingly lower values, higher prices higher values.

154. The data graphs appears to have a slight curvature which might be better described by a quadratic function, or an average of NIA and the proposed linear fit. At extreme imbalances NIA may over-estimate assumed unavoidable cost to SO of extreme shortfalls and under-estimate receipts for large spills, with the effect that the resulting incentivised amounts are respectively too low or too high, reducing incentives at those extremes. With the proposed straight line fit, the opposite might be true. Conversely, for smaller imbalances existing NIA may exaggerate the incentives on the SO, while the proposed line could reduce incentives. Have National Grid examined the correlation with other functions?

'160. The proposed indexation will have an impact upon the incentive scheme target (IBC) but not on BSUoS....'

This statement misses the point of the incentive scheme, or assumes the incentive scheme does not work!

'165. Table 23 provides an indication of the level of the adjustment the index may have provided if it had been in place over the previous three years. To consider the affect of the new index on the scheme outturn and therefore profit and loss would require the past years to be reforecast using the new index. This has not been done for this consultation.'

Does the SO think that historic outturn costs would have been different if the incentive schemes had turned out within the range of varying incentive payments rather than outside the maximum ranges?

The analysis should indicate where the proposed adjustments would have put the historic incentive schemes relative to their targets and bands.

'167. Pros

- *Removes risk of windfall gains and losses from the SO for fluctuations in the market characteristics*
- *Provides increased focus on the controllable elements for the SO*
- *Correlation between cost, SPNIRP and market length of the proposed index is better than current NIA term*
- *Removes issues with accuracy of forecast for components included in the index*
- *Removes volatile elements from forecast'*

The proposed methodology would reduce the risks of windfall gains and losses, not remove them. It would provide further transparency of forecast components, not remove issues entirely. It would reduce the impact of price and imbalance volume dependent elements from the incentivised forecast. However, users will undoubtedly still want the SO to forecast all elements, and the SO should be incentivised to provide reasonable forecasts, given that system operation is its main business and it has much data and expertise not available to users in general.

'168. Cons

- *Is not compatible with a completely unbundled scheme as there are a number of interactive components included in the index. However, it could be implemented as part of a scheme with partial unbundling e.g. unbundling of reactive and / or constraints*
- *Going forward, balancing costs / power price / market length relationship may not be the same as historical analysis has shown'*

Agree.

3.4 Individual component indexation

'170. In this section we outline the potential to develop individual component indexation. We cover the main elements of the incentive scheme; energy, reserve, constraints, -reactive and frequency response. We have not considered developing individual indexation for some components of the incentive such as black start.'

One of the benefits of identifying and analysing individual costs is the transparency it provides, which helps users understand and make their own forecasts.

'174. As discussed earlier, NIA does not currently accurately reflect the costs of resolving energy imbalance. Therefore, the main aim of an energy index would be to more accurately determine the cost of resolving energy imbalance and then to remove these costs from the incentive scheme.'

The aim is not to remove the costs of resolving energy imbalance, but to remove that part of the costs which are outside the System Operators reasonable control.

'185. To determine the most economic method of resolving energy imbalance, an EPUS methodology for determining the costs would need to be determined. ...some of the fundamental principles have been outlined in the development of the cast out modification P21110,'

A tool for determining optimum costs ex-post would provide a means of measuring actual SO performance against various elements, possibly even ex-ante uncertainty. An Ex-Post Unconstrained Schedule could be used to assess 'energy balancing and reserve' performance, and a 'constrained schedule' could show the idealised relative cost of constraints, for comparison with actual costs. We acknowledge the difficulty of creating such tools (the GOAL Replacement model used by the Pool cost some £20m to develop). The EPUS finally proposed by P211 did not consider the dynamic limitations of balancing service providers, and would therefore underestimate real achievable costs considerably.

'189. Reserve costs are generally linked to the prices received from providers who supply reserve services. These services are procured from both BM and non-BM participants. However, the majority of costs incurred for reserve services occur in the BM and are reliant on the prices submitted by providers.'

Many standing reserve costs are not incurred in the BM.

3.8 Development of Longer Term Incentive Scheme

'233. The development of options for longer term incentives has been a key element of SO incentive work in recent years. The implementation of a year on year incentive necessitates the negotiation of an incentive scheme every year and, to some extent, the forecast and target are dependant on past performance.'

The indexing of certain costs in the manner proposed in this consultation is ultimately dependent on past performance, and historic outcomes are not necessarily a good indicator of future behaviours and performance. Without methods of modelling the components of costs which allow those elements which the SO can directly influence to be distinguished from those which it cannot, it will be difficult to devise reliable incentive schemes. Without such methods, it is inevitable that recent performance comes to be used as an indicator of future performance. However, extrapolation to longer periods in the future carries considerable risk that correlations with the past become invalid.

234. Any longer term incentive scheme should be developed hand in hand and not without tools to allow relevant performance to be objectively and reliably measured. Itemisation and incentivisation of individual components of costs could be used if suitable transparent models were available to measure the success of optimisation by the SO. This could be expensive, and much more work and information would be required to confirm a net cost-benefit.

'236. The implementation of the proposed index would go some way in mitigating the volatility caused by changes in market conditions and therefore facilitates the implementation of longer term schemes.'

We are not convinced that proposed annual index coefficients will remain valid as market conditions and behaviours change. If the proposed index is adopted, it will be important to monitor carefully how valid it or particular coefficients remain valid for future incentive schemes.