Philip Davies
Director, GB Markets
Ofgem
9 Millbank
London
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28th September 2007

Dear Philip,

Review of electricity and Gas System Operator Role, Functions and Incentives (REF207/07)

EDF Energy is pleased to have the opportunity to respond to this consultation and would like to thank Ofgem for initiating this review.

Our thoughts can be encapsulated in the following four themes:

1. Volatility in system operation costs has an adverse impact on retail and wholesale market competition;

2. The operation of the transmission network should be passive to the wholesale energy market, thus facilitating, rather than distorting, competition;

3. If there is any inefficiency in the network that impacts the market, then this should be measured in order to properly incentivise the efficient operation of the gas and electricity markets;

4. The transmission system should be operated in an economic and efficient manner and the incentives should be designed to encourage this.

To summarise our answers to the electricity review questions:

- The incentive scheme should be a financial incentive linked to performance indicators that show "how efficiently" the SO is managing the system;

- The SO incentive scheme should be concurrent to the price control;

- Ofgem should consider revising the charging arrangements for BSUoS;

- The balancing services documents should be transferred to the CUSC and BSC;

- Income Adjusting Events (IAE's) allowed by Ofgem have effectively removed NGET's sharing of any downside with Users which is unfair;

- The NIA should not be based on a market reference price, but on the cost of actions that were available to the SO in the Balancing Mechanism;

- The cost of managing an offshore network should be immaterial as this is the same as connecting a generator on a spur circuit;

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- The losses incentive should be amended so that NGET are only incentivised against losses that are actually under their control;

- Any incentive scheme must recognise the inefficient cost in operating a non-compliant system;

- We would want to see greater information provided to market participants so Users can better understand actions taken by the SO.

To summarise our answers to the gas review questions:

- The role of the SO as residual balancer is significantly different to that of electricity;

- We remain concerned with the suitability of the meter assurance regime that is currently in place;

- The key issues that will impact future SO costs are the developments in the UK's gas supply and the wholesale cost of gas;

- It is appropriate to maintain an incentive on National Grid Gas (NGG) to minimise the cost of its balancing actions and its use of linepack as a balancing tool;

- It is appropriate for the gas shrinkage volume to be dependent on flows through St Fergus;

- A multi year incentive scheme is preferable;

- We are not opposed to the concept of allowing market participants to propose modifications to the statement of the SO provided these are not open to commercial manipulation.

We have provided more detailed answers to your questions below. If you have any queries then please do not hesitate to me on 020 7752 2567.

Yours sincerely,

Seb Eyre

Dr Sebastian Eyre
Head of Energy Regulation

Electricity Response Answers

Question 1: Do the current roles and functions of the SO ensure that the SO is able to operate the electricity transmission system in the most efficient and economic manner? If not, what changes do you consider should be made to the roles and functions of the SO such that it is better able to operate the electricity transmission system in the most efficient and economic manner?

Existing market arrangements do little to remove the opacity between the system and energy balancing roles of the SO. Energy balancing and the resultant imbalance cash-out pricing should not be heavily influenced by system balancing activities. However, in the GB arrangements we consistently see SO actions that are related to balancing services such as ensuring free headroom for frequency response or for constraint management, feeding into imbalance cash out prices. We have proposed a change to the BSC (P211) to try to reduce this opacity and remove the system related pollution from imbalance prices, and would like to see equivalent measures introduced to provide a proper incentive on the SO in managing the system.

Question 2: Do you consider that it is appropriate that only the SO can propose modifications to the Statements that the SO is required to have in place under C16 of its transmission licence? Do you think that market participants should also be able to propose modifications to these Statements and should they sit elsewhere, for example in the BSC?

We believe that the Procurement Guidelines and Balancing Principles Statement should be amended and incorporated into the CUSC as these documents are similar to other ancillary services documented in the CUSC. Similarly, the Balancing Services Adjustment Data and Applicable Balancing Services Volume Data methodology statements should be incorporated into the BSC as these relate to cash out pricing arrangements and balancing volumes respectively.

Question 3: Do you consider that the costs incurred by NGET in its role as electricity SO represent the costs that would have been incurred by an economic and efficient SO? Are there particular areas where you consider that NGET has not incurred costs economically and efficiently? If so, please provide details.

The BSUoS cost increase of 44.3% after the introduction of BETTA can hardly be considered economic or efficient as BETTA has not provided any significant benefit in the energy market to offset these costs. In particular, constraint costs have increased from £15.1 million in 04/05 to £108.1 million in 06/07. Much of this cost increase can be attributed to constraints within Scotland and on the cheviot constraint between Scotland and England. Scottish companies are able to significantly benefit from these constraints financially, whilst other users have to pay for the costs via BSUoS.

It is an indication of how transmission and trading arrangements fail when the transmission system is non-compliant to standards (such as the GBSQSS) which recognise the economic case for investing in the system. As the costs of constraints are far higher than the cost of investing in the transmission system we can only state that it is fundamentally important for the industry that the transmission system in Scotland is compliant. If this situation is not changed then system operation will remain a cost burden and a competitive distortion to the market.

Question 4: Do you agree that through BSUoS is the most appropriate way to recover the costs incurred by the SO? If not, please provide details of how these costs should be recovered.

BSUoS is a uniform smear of the costs of balancing the system, charged to all parties with metered volumes relative to the total system volume (i.e. generation and demand taken together). We see this charge as inherently fair if balancing services, trading arrangements and the transmission system facilitate a competitive market. BSUoS is particularly volatile and unpredictable because it is charged ex-post on system operation costs incurred in each half hour. This volatility is difficult for suppliers and generators to manage, and in particular, is problematic on the supply side when pricing contracts and tariffs. Suppliers' and generators forecasts of BSUoS will inevitably be incorrect, leading to inefficiency in charging it through to customers.

We would support a revision to the charging approach, possibly moving from an ex-post half hourly charge to an ex-ante half hourly BSUoS charge, for the forthcoming year. A similar approach to that currently used for TNUoS charging may be suitable, where any inaccuracy in the forecast charge vs. required recovery could be managed by an over or under recovery charge in the calculation for the following years charge. Should the ex-ante charge deviate from the actual BSUoS costs incurred, NGET would have to finance a cash-flow deficit, something it does not have to do with current BSUoS charging. However, with the lowest cost of capital for the industry, we believe that it is best placed to manage the BSUoS cash-flow effectively.

The ex-ante BSUoS charge could be shaped half-hourly and seasonally to focus costs into periods where expensive actions are most likely to be taken. This would not be a new concept as option fees for ancillary services are currently targeted to imbalance prices in this way via the Buy Price Adjuster (BPA).

Question 5: Do you consider that previous SO incentive schemes have been effective in ensuring that NGET as SO has operated the electricity system in an efficient and economic manner and managed the external costs of operating the system effectively? To what extent was the increased level of system operation costs incurred by the SO in 2006/07 attributable to the absence of an incentive scheme for that period? Please provide details of any areas where you consider that the SO incentive schemes have not been effective.

Whilst we are not best placed to answer this question, we can provide some observations on the efficiency with which the SO has managed the system over previous SO incentive schemes. Firstly, the significant cost increase after BETTA is testimony to wider issues surrounding system operation rather than the effect of a yearly incentive scheme. Secondly, the cost escalation that occurred when there was no scheme in place, indicates that sufficient incentives are important in reducing costs when regulating monopoly activities. On balance, we believe that the incentive schemes for the years 2001/02 – 2004/05 have not been effective, as each of the schemes has significantly over forecasted the cost of system operation resulting in unnecessary payments being made to NGET.

Another example of the schemes failing has been shown by some of the recent IAE's that have been submitted by NGET, especially the 2005/06 IAE for frequency response and Scottish constraints. This should have been a year where the scheme should have been more penal on NGET, but the £29.5m IAE allowed by Ofgem for 2005/06 effectively removed the sharing factor of any downside with Users of the system. Previous schemes provided NGET with significant upside, yet as soon as there was any downside NGET was able to use an IAE to escape most of the financial impact.

Question 6: Do you consider that a sliding scale scheme is the most appropriate way for an SO incentive scheme to operate? If not, please indicate what you consider to be a more appropriate type of scheme.

We believe that the use of a sliding scale is an appropriate way for the SO incentive scheme to operate, but do not agree that this should be limited by a cap on payments and a floor on losses. This is because if NGET were to hit these upper and lower limits part way through an incentive scheme, then there would be no further incentive for them to manage the system in an efficient manner after this point.

Question 7: Do you consider the use of the Net Imbalance Adjustment to be an appropriate way of adjusting for the costs resulting from market participants' actions that the SO has little control over? If not, how could this adjustment be improved?

Resolving market imbalance in a cost-effective manner is one of the primary roles of the SO, and it is recognised that the SO has no influence over market length, and only a degree of influence over the cost of keeping the system in balance. The NIA currently provides some protection for NGET against changes in wholesale market prices and the extent of party contracting by valuing the actions it takes against a market reference price multiplied by a factor 0.5 when the market is long and a factor of 2.5 when the market is short. This implies (because of the size of the premium/discount to the market reference price) that as long as the actions taken are helping to restore the system to balance then the SO should not be held accountable for the cost of them, even though it may have been able to resolve the imbalance more effectively by taking cheaper actions.

We believe that the NIA should not be based on a market reference price, but on the least expensive actions that the SO could have taken in the Balancing Mechanism. The Incentivised Balancing Costs (IBC) could then be calculated against the difference between the price of the Cost of System Operation in the Balancing Mechanism (CSOBM) actions that NGET actually took and those actions that it could have taken, which can be represented by a price calculated under an ex-post unconstrained schedule (EPUS). The NIA would therefore expose the SO when actions are taken out of price order. It would need to be a “clean EPUS” representing the raw cost of the actions available to the SO, rather than the final Cash-Out calculation, which would include an uplift for the reserve option fees that the SO is required to pay.

The resultant difference between CSOBM and the EPUS could be considered either [1] incentive for the SO to resolve NIV in the most economic way [2] a measure of the inefficiency of the transmission system.

Therefore rather than: $NIA_j = TQEI_j * NIRP_j$

Where $TQEI_j$ is the net imbalance volume (NIV) and $NIRP_j$ is the Net Imbalance Reference Price;

We would suggest: $NIA_j = TQEI_j * EPUS_j$

We do however recognise that some sort of adjustment would be required to the EPUS to provide the SO with a fair target (performance will always be negative except where NGET can outperform the EPUS by contracting ahead of time). The adjustment could be a fixed cost agreed ex-ante or a percentage premium/discount applied to the EPUS (although not of the same magnitude of that currently used to derive the NIA). This point is illustrated in more detail in Appendices one and two.

Question 8: Is it appropriate for participants (including the SO) to have the ability to raise Income Adjusting Events when unexpected events occur resulting in increased or decreased costs? If not, how could such cost uncertainties be addressed under an incentive scheme?

An “income-adjusting event” should be a rare and very specific event outside anything that NGET might have expected when, on the basis of the range of possible outcomes, it negotiated with Ofgem the parameters for a balanced and reasonable scheme. In the future, there should be a clear ex-ante definition of what does, and what does not, constitute an income-adjusting event (IAE). An income-adjusting event should be a genuine, specific and quite exceptional event and not simply based on “it was a bad year overall”. Also, IAEs are an ex-post charge which may not be recoverable through competitive tariffs.

If the SO incentive scheme is of five years duration then there is less argument for IAEs , as it is likely that a number of events (either adverse or favourable to the GBSO’s target) will occur.

Question 9: Do you consider that the costs of operating offshore networks should be included in the SO incentive scheme? Are there any other additional elements that you consider should be included? Are there elements that are currently included in the scheme which should be removed?

The cost of managing the offshore network should be immaterial as we consider this to be connecting a generator in much the same way as any generator on the end of a generator spur circuit. It is a wider issue that offshore generation will be predominantly wind, which is expected to place greater reserve costs onto the SO if it represents a significant proportion of installed capacity.

Question 10: Do you think it is appropriate to consider unbundling the electricity SO incentive scheme? If so, which areas do you consider should be separated out and how might the SO be incentivised in these circumstances?

We believe that the bundled approach in electricity is appropriate as the SO is incentivised to concentrate on reducing overall costs rather than maximising the profits it makes from the individual elements of the scheme.

Question 11: Would longer term SO incentive schemes provide greater opportunities for investment that ought over the longer term to result in greater net efficiencies in SO costs?

We wish to reaffirm our support for longer-term incentives than those arising from a scheme of a single year’s duration. We played a direct and leading part in the Supplier Negotiating Team for the first SO incentives schemes, UMIS and TSS1, TSS2, and on each occasion there was a clear intent expressed, accepted by both supplier and NGC teams, that future years’ schemes would move to being multi-year at the very earliest opportunity. In a single year scheme, even with a sharing factor of 50%, any capital spent on reducing SO costs has to have a pay-back of 1 year, meaning that it must have better than a 200% return in respect of the annual saving in SO costs compared to the capital investment. This is because, from NGET’s point of view, any gain in the next-following year may be taken into account in its entirety in setting the SO incentives scheme target.

We would like to see an alignment of the TPCR and SO incentive scheme so the regulator can evaluate the trade off between efficient capital and operational expenditure. The level of capital expenditure will no doubt influence the levels of operational expenditure.

Question 12: If we were to consider a longer term SO incentive schemes, what are the key drivers of SO costs that would need to be considered over the longer period? In what way could these drivers be captured in the incentive scheme?

We would expect any long term SO incentive scheme to account for:

- **Spot power prices** – the marginal fuel cost will influence the cost of operating the system.
- **Constraints** - the cost of operating a non-compliant system and managing constraints in the near term.
- **Margin** –the available headroom/footroom in the market and the proportion of actions that the SO will need to take for system rather than energy balancing purposes.
- **Investment** - the level of investment in the transmission system to resolve constraints.
- **Regulatory change** - any reduction in the GBSQSS standards or radical transmission access proposals, which may increase constraints. Changes to the balancing incentives on parties could also impact the amount of actions that the SO has to take to resolve energy imbalance.
- **Grid Code developments** - the development of the Grid Code and the obligations on generators in the Connection Conditions (CC) to provide balancing services.
- **Reserve procurement** - the procurement of reserve and the availability of generators to provide such services.

It must also recognise whether the SO will be operating a constrained system for the entirety of the scheme or if the system will become more balanced over the incentive period.

Question 13: What are the key developments that will affect future System Operator costs? How will these developments impact on costs?

Please see our answer to Question 12 above.

Question 14: Are there areas in which the current transmission losses incentive scheme could be enhanced to improve further the incentives on the SO to operate the electricity transmission system in an efficient and economic manner?

In a self-despatch market such as NETA, the SO has a degree of influence over the level of losses through network configuration and the location of its balancing actions. We therefore believe it is appropriate to retain an incentive on NGET to minimise losses on the system. However, the current methodology of using total gross losses on the system as a target implies that they have control over all transmission losses which is clearly wrong.

We believe that if it is possible to identify the element of losses that are in the control of NGET (line outage pattern synchronisation with generator outages, replacement of inefficient transformers etc.) and incentivise them on that then this would be more appropriate than the current methodology.

Question 15: What additional market information do you consider should be made available to the market by the System Operator, and vice versa? Please explain how this information would improve system operation and market efficiency?

More information needs to be provided by the SO in relation to why it takes individual actions. At present, little is known as to how the SO values actions that are taken for other "non-energy" reasons such as reserve procurement and locational issues. We would like to see greater information provided so Users can better understand actions taken by the SO. For example, there is currently no data provided to market participants on how the SO evaluates MW frequency response capability, bid prices (for headroom) and response holding rates.

We would also like more transparency in relation to the Balancing Services Adjustment Data (BSAD), and in particular, the breakdown of the costs being incurred in each half hour period on a BM Unit basis.

More specifically we would like the following data to be made available:

- Frequency Response Capability matrices by BM Unit;
- Real-time units being held for Frequency Response (Firm and Mandatory);
- Earlier publication of Firm Response volumes (similar to timescales proposed under CAP158 for Mandatory Response);
- Real time response requirement;
- Response being held by Frequency Control Demand Management (FCDM);
- Reactive utilisation data by BM Unit (market and default);
- Disaggregating of the BSAD and BPA calculations;
- BM Start-up unit name and consolidated data (rather than "one-off" publication under SONAR).

Question 16: Is there sufficient transparency surrounding the SO incentives both in terms of the process for setting the incentive parameters and in terms of the information on costs provided by NGET? If not, what additional information do you consider should be made available?

Although there is sufficient consultation on the setting of the SO Incentives scheme, it, as it always will do, appears to be a high level bartering exercise between the monopoly and its regulator. This is one of the reasons why we would want the scheme to move from a purely financial incentive to being a financial incentive linked to performance indicators that show "how efficiently" it is managing to operate the system.

Question 17: Do you consider it appropriate that the electricity SO should have quality of information incentives placed on it (as is the case with the gas SO)? If so, how should the SO be incentivised?

We have already requested more information to be published by the SO so the market can understand its actions and act accordingly.

To incentivise NGET to release this information seems sensible; however we must question the value for money in incentivising a monopoly to release information to participants who have every entitlement to it, even if the benefit to industry outweighs the incentive payments to NGET. We cite the NGG incentive scheme, where far greater information has been provided to industry (with great benefit to shippers) but at a cost of £3m.

Gas Response Answers

Question 18: Are the current roles and functions of the SO appropriate, and do they ensure that the SO is able to operate the NTS in the most efficient and economic manner? If not, what changes would you recommend?

Due to the differences between the SO's role in gas and electricity, it appears that at a general level the role and function of the SO in gas is appropriate. We would note that in gas the role of the SO as a residual system balancer is significantly different to that of electricity, due to the flexibility that is present in the Gas NTS. This flexibility means that the Gas SO does not require as many tools as the electricity SO as it has a longer balancing period reflecting a more flexible transmission system.

Question 19: In the electricity market the SO as residual balancer is able to contract ahead for various services. In the gas market the SO as residual balancer does not have the same ability. Do you consider that this difference is appropriate? Please explain your view.

Whilst we note that in electricity the SO as residual system balancer is able to access a large amount of services ahead of time, EDF Energy believes that this reflects the difference between the Gas and Electricity SO as residual balancer and how the two transmission systems operate. In particular we note that the electricity system has to be balanced in real time and so NGET is required to access services ahead of time to ensure that the system remains secure. In gas there is sufficient flexibility so that the system does not have to be balanced real time, or even at the end of the day, with the SO having the choice between balancing the system or allowing a reduction in linepack. We therefore believe that the difference is appropriate, reflecting the different requirements of the two systems.

Question 20: Do you consider that the costs incurred by the SO represent the costs that would have been incurred by an economic and efficient SO? Are there any particular areas where you consider that the SO has not incurred costs economically and efficiently? If so, please provide details of these areas and why you consider that to be the case.

It is hard to judge whether the costs associated with unaccounted for gas has been efficiently incurred or not. If the cost of reducing the volume, and so value, of unaccounted for gas greatly outweighed the associated volume (and therefore cost reduction) then it would appear that this was being economically and efficiently occurred. However, in order to undertake this analysis we would require more information on the cost of reducing this volume. Further, given the size of the reconciliations that took place last year at £12.09m, EDF Energy remains concerned with the suitability of the meter assurance regime that is currently in place. Whilst we recognise that the majority of meters that impact on this are GDN owned and operated, they are governed by both a NExA and the Offtake Arrangements Document (OAD) of the UNC. National Grid Gas (NGG) will be party to both of these documents and it would appear appropriate that an incentive was developed to ensure that NGG ensured an appropriate assurance regime was in place. On a simple level this could involve excluding any meter reconciliation adjustments from NGG's shrinkage costs, or developing a sharing factor so that NGG's incentive payment was reduced.

Further it is equally hard to identify whether NGG's OM Costs have been economically and efficiently incurred. This could only be achieved by identifying what NGG's costs would have been were they to have procured these services from the market at market prices. We would further note that some of the issues associated with this are also being covered by Ofgem's LNG Price Control Review and would like to seek clarity as to how these two consultations will operate and interact.

Question 21: What are the key developments that will affect future System Operator costs? How will these developments impact on costs?

The key issues that will impact on the SO costs are the developments in the UK's gas supply as the UKCS continues to decline, and the wholesale cost of gas. As the UKCS declines, it is likely that the geographic supply of gas to the UK will change. This would impact on NGG's shrinkage requirements as the system would be reconfigured, thereby impacting on the cost of transporting gas around the UK. This is especially the case if new gas supplies enter the UK closer to demand. In addition, the wholesale cost of gas will impact on the cost of transporting this gas around the UK using both conventional gas turbines and new electric compressors.

Question 22: Do you consider that the current form of the residual gas balancing incentives is appropriate? Please explain your reasoning.

It appears appropriate to maintain an incentive on NGG to minimise the cost of its balancing actions and its use of linepack as a balancing tool. However given NGG's performance under the price incentive, it would appear that the form of the incentive could be improved. In particular it appears perverse that NGG can make the maximum gain under this incentive 33% of the time when it takes no actions because Shippers have balanced the system. It would therefore appear appropriate to develop an incentive so that NGG is not rewarded for Shipper actions on days when no balancing actions are required (although it is important that this is developed in such a way to ensure that NGG is not perversely incentivised to take balancing actions when none are required). Further, given NGG's performance under this regime it would be appropriate to ensure that the price targets and payments remain appropriate.

Question 23: Do you believe that the existing linepack incentive has little impact on the behaviour of the gas SO? If so, do you have any suggested improvements for this aspect of the incentives?

Whilst it would appear that the linepack incentive has little impact on the behaviour of NGG, this could partly be explained by the interaction with the pricing element of the residual balancing incentive. If the pricing incentive was set at an incorrect level or form, then this would reduce the impact of the linepack incentive. It is therefore important to ensure that the form and incentive levels of these two incentives are set at such a level to compliment each other.

Question 24: Is it still appropriate for the gas shrinkage volume target to be dependent on flows through St Fergus? If yes, please provide details of the relationship. If no, please explain your reasoning and provide your views on how the target should be set.

Given the costs associated with transporting gas from St Fergus, and the uncertainty surrounding future UK supplies, we believe that it is appropriate for the gas shrinkage volume target to be dependant on flows through St Fergus. This should ensure that NGG is not penalised for increased flows through St Fergus or rewarded for reduced flows which it has no control over. However it may be more appropriate to set a sliding scale incentive on this as opposed to a three tier approach.

Question 25: Is the current gas cost reference price methodology still appropriate? If not, please explain what an appropriate methodology would be.

It is not clear from the information available whether the current gas price methodology is still appropriate or not. In particular, we understand that historically NGG had contracts to meet its shrinkage requirements which impacted on this methodology, but it is not clear whether those contracts are still active or not. We also believe that it would be appropriate to develop a market index price for shrinkage gas costs, similar to that developed in the one year GDPCR for 2007-

08. However, when developing a methodology based on a market index it is important that this methodology is simple and transparent to aid industry understanding.

Question 26: Is the current form and scope of the gas system reserve incentive still appropriate (in terms of the volume and source of gas reserve bookings the SO considers necessary for the safe operation of the network, the contestability and locational nature of some of these requirements and the price at which it is efficient for these bookings to be made)? Do you consider that the sharing factors, cap and floor for this incentive are still appropriate? Please explain your views.

With the information available it is hard to identify whether the forma and scope of the gas system reserve incentive remains appropriate. At a general level therefore the current sharing factors, cap and floor appear to remain suitable based on the information that is currently available.

Question 27: We would welcome views on the indicative data provided by NGG on its requirements for gas reserve from April 2008, including views on its continued utilisation of LNG storage at the Isle of Grain importation facility.

EDF Energy has no views on this data.

Question 28: Would the increased stability of gas SO incentive schemes of longer duration be preferable to the increased flexibility offered by schemes of a shorter duration? Please provide your reasoning.

As in electricity, we believe that a multi-year SO incentive scheme is preferable to a single year SO incentive scheme. In particular we believe that this will provide predictability to NGG on the operation of these schemes and allow NGG to take the appropriate decisions to ensure that the gas system is operated in an economic and efficient manner. This would avoid unnecessarily high and unrealistic returns in order to make an investment attractive with a single year pay back period.

Question 29: Are there any aspects of the gas SO incentive schemes that you consider would be more effective if bundled, rather than remaining in their current form? Please provide details of how this may be achieved.

We do not believe that it would be appropriate to bundle the gas SO incentive scheme. We believe that this provides transparency to the market when identifying the appropriateness and impact of any incentive, and ensures that any failings/improvements on specific incentives are easily identifiable.

Question 30: Is it appropriate for participants (including the SO) to have the ability to raise Income Adjusting Events when unexpected events occur resulting in increased or decreased costs? If not, how could such cost uncertainties be addressed under an incentive scheme?

Please see our answer to Question 8.

Question 31: Do you consider that it is appropriate that only the SO can propose modifications to the Statements that the SO is required to have in place under Special Condition C5 of its GT licence? Do you think that market participants should also be able to propose modifications to these Statements?

EDF Energy is not opposed to the concept of allowing market participants to propose modifications to the Statements that the SO is required to have in place under Special Condition

C5 of its GT Licence. We believe that this introduces the possibility of introducing innovation into NGG's System Management Principle Statements and could ensure that effective procurement strategies are implemented for these services. Further it is likely that these statements could be developed so that NGG sought to procure services that market participants wished to offer. However we are unsure as to whether there is significant appetite amongst market participants at the present time to influence this statement, and we are concerned that this would open the statements up to manipulation for commercial gain. We would therefore require assurances surrounding the governance arrangements associated with these documents before we would be able to support any proposal to change these.

APPENDICES

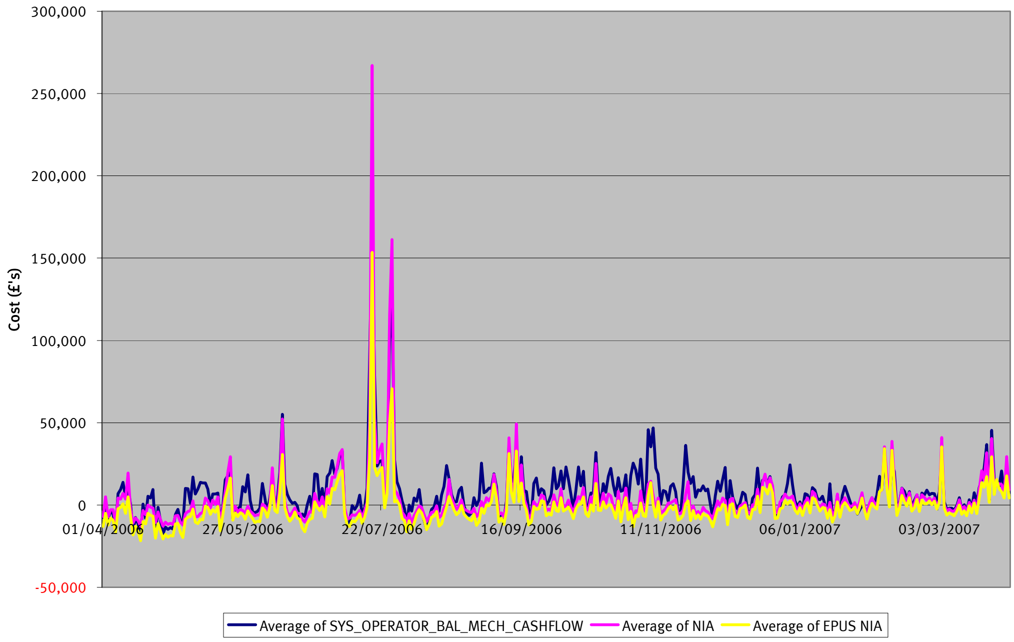
Appendix 1

Table showing the total current NIA for April 06 to March 07 versus the EPUS NIA and the effect on CSOBM[1]

	CURRENT	EPUS
NET CSOBM	78,591,888	168,063,175
NIA	64,526,170	-24,945,117
TOTAL CSOBM	143,118,058	143,118,058

Appendix 2

Graph showing daily average current NIA for April 06 to March 07 versus EPUS NIA and outturn CSOBM



[1] There was no incentive scheme in place for 06/07, but the NIA data was made available to industry. The EPUS prices have been calculated using the Elexon modelled data provided to the P211 working group.