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Dear Philip,

Review of Electricity and Gas System Operator Role, Function and Incentives: Initial Thoughts (Ref 207/07)

National Grid[1] welcomes Ofgem's review of System Operator roles, functions and incentives for both gas and electricity. Financial incentives on System Operation continue to work successfully to ensure that the costs to consumers of operating the gas and electricity transmission systems are managed efficiently and economically ensuring that the interests of National Grid are aligned with that of consumers.

We agree with Ofgem that a review of the respective incentives and the roles for both SOs is timely given the changes occurring in the energy industry, in particular:

- The shift in sources, diversity and location of gas supplies in Great Britain, with the decline of the UKCS and increases in interconnector and LNG import capacity;
- The similar changes in the sources of electricity supply, with the increase in renewable generation capacity;
- Ongoing changes to the gas and electricity transmission access frameworks; and
- The maturing of both gas and electricity wholesale markets since the introduction of new trading arrangements in both markets over seven years ago.

We agree with Ofgem that one of the main aims of the review should be to consider longer duration incentive schemes for future gas and electricity incentive arrangements. It is our view that, with appropriate changes to the existing incentive structure, longer duration schemes can help to reduce network operation costs by further helping to provide a more stable foundation and certainty for innovative investment by, and development of, the SO functions.

[1] National Grid is System Operator for both the gas and electricity transmission networks in Great Britain. We also own the high pressure gas transmission network in Great Britain and the electricity transmission system in England and Wales.

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It is our view that the development of one year schemes for 2008/09 should be used as a stepping stone for possible longer term schemes being introduced from April 2009 onwards. In some areas, incremental development of the current arrangements for 2008/09 provides the opportunity for some potential changes to be 'proved' ahead of potential implementation within longer term schemes.

To achieve agreement on longer term schemes it will also be key to establish a broad understanding of and consensus on the likely drivers of cost over the term of the scheme. Again, work for the 2008/09 schemes should help to lay the foundations for this understanding and we also welcome the contribution to this that will be made by Ofgem's industry workshop on the SO review to be held in November.

Finally, we agree with the areas for review of the SO role identified by Ofgem. The SO role is something that should be under constant review to ensure it covers those areas where the SO is best placed to work efficiently in the interests of consumers and National Grid is committed to the continued development of its role to best meet the interests of consumers within both gas and electricity markets.

Our replies to the specific questions posed in the consultation document are detailed in the appendix to this letter. If you would like to discuss any aspect of our response or the review please do not hesitate to contact me.

Yours sincerely,

Chris Bennett
Regulatory Frameworks Manager

nationalgrid

APPENDIX

Questions regarding the role, function and incentives on NGET in respect of its electricity System Operator function

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?

Yes, our current role and functions, as laid out in our Transmission Licence and associated documents[2] ensure that we are able to operate the electricity system in the most efficient and economic manner.

Moreover, the governance frameworks in place facilitate the development and assessment of these roles and functions and the governance of them with the aim of ensuring economic and efficient operation of the transmission system and discharge of our duties as GBSO. In this regard National Grid and the industry are able to develop the framework within which we operate to ensure efficient and economic operation. This review via the industry code documentation ensures continued development of an efficient framework, role and functions for the SO which, in the end, is to the benefit of consumers.

Notwithstanding the above, this overarching review of our role and function is timely given the changes taking place in the industry, with increased investment both in networks and in new sources of electricity supply from fossil and renewable sources and given the fact that we now have a number of years' experience of operating in the NETA/BETTA environment.

This review should consider potential changes to the current SO role and functions to meet the needs of the industry and consumers that arise as a result of the wider changes occurring within the industry and experience of the current NETA/BETTA environment. In particular, we agree with Ofgem's view that it is important to look at the possibility of longer duration incentive schemes and the greater stability and certainty for customers and for investment in further efficiencies that should result. We would identify continued development of the SO-TO framework to facilitate the management of network constraints in Scotland as area for consideration as part of this review. We also support the further examination and development of options for the role of the SO with regard to the provision of increased market information.

[2] The NGET's System Operator role and functions are described in NGET's Transmission Licence and associated documents which include the Grid Code, CUSC, BSC, STC, Procurement Guidelines and Balancing Principles Statement.

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 the market participants should also be able to propose modifications to these Statements and should they sit elsewhere, for example in the BSC?

Partly yes: Condition 16 of our Licence requires that we have in place four statements:

Two of these statements describe the balancing services we expect to procure and the manner in which we expect to use these services.

- Procurement Guidelines Statement (PGS)
- Balancing Principles Statement (BPS)

The other two statements relate to the treatment of the costs and volumes of certain balancing services within the BSC:

- Balancing Services Adjustment Data Methodology Statement (BSAD)
- Applicable Balancing Services Volume Data Methodology Statement (ABSVD)

The BPS and PGS refer to our procurement and use of balancing services in line with our licence obligations. As such, the appropriate place for these two statements to sit is under our transmission licence. It would not be appropriate for these two statements to sit under the governance of the BSC. We note that there is an opportunity for all participants to comment on these statements via an annual consultation process. This process ensures that all comments and ideas are collated and coordinated to develop the C16 statements effectively.

In principle we consider that, because BSAD and ABSVD, relate to the treatment of volume and costs of balancing services within cashout that these statements could sit equally under National Grid's transmission licence (as now) or, if there was industry support for it, within the BSC. If these two statements were to come under BSC governance then consideration would have to be given to how the costs of changes to these systems that deliver BSAD and ABSVD data and the systems themselves would be managed on an ongoing basis.

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.

Yes, the costs incurred by NGET in its role as electricity SO represent the costs of an economic and efficient SO. It is a condition of NGET's Transmission Licence that it acts economically and efficiently in all its SO activities. Our balancing activity is annually audited by an outside, independent body that verifies National Grid has been operating in an efficient manner. The presence of financial incentives provides further incentives for NGET to act innovatively to minimise its SO costs efficiently.

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.

Yes, it is our view that BSUoS is an appropriate way to recover the costs incurred by the SO however we welcome industry views on ways in which the BSUoS charging framework can be further developed.

Question 5: Do you consider that previous SO incentive schemes have been efficient 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 2006/7 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.

Yes, 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 and efficiently.

As a result of the lack of incentive scheme for 2006/07, our costs were heavily regulated by Ofgem, to whom we provided significant additional cost information for regulatory monitoring. The increases in costs seen during 2006/07 have been explained in detail to Ofgem and the industry at public fora and do not relate to the lack of incentive. Primarily, the cost increases seen in both 2005/06 and 2006/07 relative to previous years were driven by:

- Increase in market size with the introduction of BETTA;
- Increase in generation fuel costs and wholesale power prices;
- Network constraint costs;
- Increases in frequency response prices as a result of the introduction of CAP047.

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.

Yes, we consider that a sliding scale scheme is the most appropriate way for an SO incentive scheme to operate. This allows suitable upward and downward sharing factors to be set based on an agreed view of the likely risk and reward.

When considering what parameters to set in a sliding scale scheme it is important to recognise:

- The likely range of costs and cost risk, and the ability of the SO to reduce these costs or contain cost increases through the use of tools and efficiency measures it has available;
- Cost factors outside the SO's control and correct for these, such as the current NIA adjustment factor that corrects for market length;
- Any scheme should reward efficiency improvements by the SO that drive cost reductions or mitigate expected cost increases, and;
- The wider incentive framework should ensure that additional costs incurred by the TO in facilitating SO requirements to minimise costs are fully funded (see below).

With regard to this final point, above, at present the TO / SO arrangements currently in place with the Scottish TOs allow full funding of additional Scottish TO costs through the payment of ‘outage management costs’ by NGET to the Scottish TOs. However, funding for additional costs incurred by NGET as TO in England and Wales in support of SO requirements are assumed to be earned through out-performance against the SO external cost incentive. Given that NGET has not earned any income, and indeed has lost money, on SO incentives since 2005/06, additional NGET TO costs incurred since 2005/06 have, in effect, not been funded.

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?

The Net Imbalance Adjustment is an appropriate way of adjusting for some costs that result from market participants’ actions that the SO has little control over and it remains a necessary part of the incentive scheme. We would suggest two possible areas for review of the NIA framework:

1. A review of NIA should consider whether the adjustment should also encompass the variability in balancing costs for Reserve that arise due to changes in participants’ actions, predominantly market length but also possibly market free headroom.
2. At present NIA is based on the BSC volume parameter TQEI. TQEI provides a very accurate figure for the volume of corrective actions taken by the SO to correct for market length. However, it does not include the volume of actions instructed on NGET’s Ancillary Service contracts with non-Balancing Mechanism providers: typically with demand side or small embedded generation. This volume represents a small component of NGET’s actions to correct for the market’s residual mismatch between supply and demand however at present this small component is not correctly funded within the incentive framework.

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?

Yes, Income Adjusting Events (IAEs) are an appropriate mechanism for managing, ex-post, the potentially high costs of unforeseen or unforeseeable events and, as such, IAEs are similar to 'force majeur' provisions in any standard contract.

We note that the majority of respondents to Ofgem's previous consultations on incentives for 2006/07 agreed that IAEs were an appropriate mechanism. Both National Grid and other parties can raise IAEs. All IAEs are consulted upon by Ofgem, with the Authority having final decision on approval. This gives adequate protection to consumers.

Due to the nature of operation of the transmission system and the governance arrangements, there are many potential incidents and market changes that can significantly influence the costs of system operation that are outside the control or influence of the SO. A method of funding the SO for costs incurred due to such unforeseen events or market change is required and in our view the IAE mechanism is the most appropriate way of meeting this requirement.

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?

Offshore networks will form part of the GB transmission system and therefore it is our current view that the costs of managing this single system, such elements as system reserve and frequency response, should be included within the SO incentive scheme.

We note that the arrangements for Offshore are subject to ongoing consultation and development and it will be easier to form a clear view on these issues once the framework has been confirmed. However, we do not believe that this is an issue that needs to be addressed for 2008/09 but should be considered as part of the longer term review once there is greater clarity as to the proposed framework for Offshore.

With regard to other elements, we believe that in particular it is timely to review whether the continued inclusion of Transmission Losses within the SO incentive is appropriate. Since the introduction of BETTA transmission losses have increased significantly and they also have greater potential to vary whilst the ability of the SO to influence the level of losses has reduced. In addition, the possible introduction of a variable transmission losses framework within the BSC would bring into question the need for the SO to be incentivised to drive efficiency in this area.

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?

No. National Grid is in favour of a single bundled scheme for electricity, as generally our actions can meet more than one requirement. However, a single bundled scheme can be partly 'unbundled' by using target adjusters to take account of known cost drivers that are outside the control of the SO. The use of target adjusters improves the scheme by adjusting the target for factors outside the control of the SO and thereby avoiding windfall gains or losses.

Ofgem have used such an approach with the gas SO in relation to the shrinkage incentive for 2007/08 by including a parameter to adjust the incentive target based on gas flows at St Fergus, which are outside the Control of the SO. For the electricity SO we already have an adjustment for market imbalance and for previous schemes an adjustment for power price has also been considered, with no final conclusion drawn.

We consider that both for 2008/09 and as a facilitator for longer term schemes, a number of possible adjusters should be considered as possible parameters to adjust the target based on factors outside the control of the SO:

- Variation in Power prices and fuel prices;
- Volume or number of transmission outages, as these drive constraint costs, particularly for the Scotland-England constraint boundary.

Predominantly in regard to schemes after 2008/09 consideration should also be given to adjusters for:

- Level of wind output, as this is expected to drive some changes in system operation costs;
- Frequency response holding prices, which have been a major driver of costs over recent years.

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?

Yes. Longer term schemes would allow for long term investment and innovation within the corresponding longer term payback period, and provide some certainty to allow long term procurement of services. It is our view that longer term schemes, both in setting a target and in the discussion that is required to set the target, will also give the industry greater clarity as to their future BSUoS costs and thereby allow parties to better forecast their longer term costs. Based on these two points, we would support the further examination and development of longer term schemes.

As part of the development of longer term schemes consideration needs to be given as to how to manage the agreement of scheme parameters given the greater uncertainty of costs further into the future. As the costs to be incentivised under a longer term scheme are inherently more uncertain, additional measures such as cost adjusters should be used to help reach agreement on the scheme target and to maintain effective incentivisation of the SO for the duration of the scheme.

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?

As described in our appendix to Ofgem's consultation, Appendix 14, there are a number of factors that affect the costs of balancing the system. A number of these are not within the control of the SO. Some examples of cost drivers are:

- Wholesale power prices, generation fuel prices and resultant BM prices;
- NIV, and the level of free headroom available from the market, driving the procurement of additional reserve;

- Network outage plans, which will be unknown or very much more uncertain at the time of scheme agreement, for the later years of a longer term scheme;
- Holding prices for Frequency Response services;
- Changes to system operation costs, including reserve and constraints, associated with additional wind generation, and;
- Changes to the market arrangements, driven by Code modifications.

As described in more detail in our appendix, there is natural uncertainty associated with these areas, with many cost drivers being outside the direct influence of the SO. As described in our answer to question 10, above, the way to manage some of these uncertainties within the scheme parameters is through the use of scheme target adjusters.

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

Full detail on our view of the key developments is given within our appendix to Ofgem's consultation, appendix 14. In summary:

- Development of renewables, especially the increase in wind is one of the key drivers for future System Operator costs. Due to the variable output of wind, we expect there to be an increase in reserve requirements and dynamic response requirements. In addition, the location of new wind is mainly projected to be in Scotland and therefore there would be a subsequent effect on constraint costs.

- The introduction of LCPD will have an effect on our costs due to the limitation on stack running hours for those generators opted out of the LCPD. Our initial assessment suggests that reserve, constraint, response and black start costs have the potential to increase. However, the extent of any increase depends on the operating regime of the generators opted out of the LCPD.

- The development of transmission access arrangements could significantly affect how the system is operated and the costs of operation. These issues are being discussed elsewhere as well as part of the System Operator review.

- In addition, interaction with other European markets will affect the costs of system operation, both in terms of potential benefits and cost increases, mainly associated with the changes in flows across those interconnectors. With the potential development of additional European interconnectors, there will be increased interaction with European markets and a subsequent effect on system operation.

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?

As stated in our answer to question 9, we believe that it is timely to review whether the continued inclusion of Transmission Losses within the SO incentive is appropriate. Since the introduction of BETTA transmission losses have increased significantly and since BETTA they also have greater potential to vary and the ability of the SO to influence the level of losses has reduced. In addition, the possible introduction of a variable transmission losses framework within the BSC would bring into question the need for the SO to be incentivised to drive efficiency in this area.

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?

National Grid has engaged with the industry through the Electricity Operational Forum, the Demand Side Working Group (DSWG) and an Electricity Demand Forecasting Workshop to solicit feedback on Electricity Market Information issues. This work to date, the feedback provided and the options going forward are included in our Consultation Report[3], issued 1 August 2007. This consultation asked the industry a number of questions regarding industry information provision and requested their opinion on how to progress.

Increased market information can help to improve the efficiency of those markets. In this regard we would point to our consultation document for discussion of this and, as a further illustrative example of information development, to CUSC Amendment 158. CAP158 was recently raised by National Grid following work with the Balancing Services Standing Group. CAP148 proposes to increase the timeliness of frequency response data with the aim of further facilitating a competitive response market and thereby helping to reduce the costs of system operation. In contrast, there are some areas where additional information could lead to an increase in the costs of system operation, such as the ex-ante publication of details of individual transmission constraints.

Question 16: Is there sufficient transparency surrounding the SO incentives both in terms of the process for setting and 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?

We welcome increased transparency of incentives and we believe that a high level of transparency of information provides for an informed debate and, in the end, an appropriate incentive framework. A better understanding of our costs will ensure that the incentive target setting process runs more smoothly and provides the industry with comfort that our costs and risk reward balance are commensurate with the activities we undertake.

We continue to work to improve the level of information delivery within the process and have delivered a number of improvements. For example we now provide regular updates of our incentivised costs at operational fora. We also undertook a detailed workshop in January 2007 to explain the rises in BSUoS and Incentivised costs seen since BETTA Go-Live.

We recognise there is always more that can be done in this area: we are working on a revised version of our Monthly Balancing Services Summary, and; we also believe that more could be done to present our forecasts and outturns in terms of BSUoS costs as well as incentivised costs and, in doing so, explain the differences between these numbers. This was something begun at the January 2007 workshop and continued at operational fora following requests from the industry.

[3] A copy of this document can be found at the following address: http://www.nationalgrid.com/uk/Electricity/Data/electricitymarketinfo/

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?

Provision of information is vital in developing and operating a robust market. The costs of development and delivery of systems to provide such information need to be funded. In some cases incentivisation is appropriate, in other cases it may be appropriate to fund these changes directly. In either case, there needs to be robust justification and approval process to ensure the investment costs are suitably justified.

At present NGET's budget from which any new developments must be funded was determined as part of the Transmission Price Control and is fixed for the five year period. At the time of agreement, National Grid proposed that a more flexible funding arrangement should be put in place to allow NGET to respond more flexibly to requests for new information that were appropriately assessed and approved. This proposal was not taken forward by Ofgem at the time. However we believe that a more flexible approach to funding changes that have the support of the industry would be appropriate.

Questions regarding the role, function and incentives on NGG in respect of its gas System Operator function

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?

Yes, we consider that the role of the SO is appropriate given the current commercial framework under which the gas market operates. The role of the SO is to ensure that the system is operated safely and provide information to the market in a way that allows the gas market to function effectively.

The role of the SO is something that should be under constant review to ensure it covers those areas where the SO is best placed to work efficiently in the interests of consumers. We consider that ongoing initiatives to develop the SO role and functions are necessary to sustain and develop a well-functioning and competitive UK gas market.

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?

Yes, we believe the difference in approaches taken by the gas and electricity system operators are appropriate, given the differences between the market structures and the different timescales over which balancing needs to take place.

The inherently different timescales over which supply and demand must be balanced and hence the need for a Gate Closure in electricity is a key driver behind the difference in how the residual balancing activity is conducted. In electricity, the SO is the only party balancing after Gate Closure and therefore has to procure reserve (and other balancing services) potentially ahead of Gate Closure with the objective of ensuring the necessary availability of plant with required delivery characteristics to be able to balance generation and demand second by second at the minimum overall balancing cost. In gas, there is no concept of Gate Closure and the market continues to seek to balance itself by the end of the gas day therefore the SO's residual balancing objective is to minimise its intervention by only take balancing actions where it believes the market will not balance itself in the timescales necessary to keep the system within safe operating limits.

The gas balancing regime is currently structured such that NGG is incentivised to minimise the actions it takes to balance the system. As such NGG would only undertake gas market trades each day where, in its judgement, it is necessary to do so. NGG would seek to minimise the price of trades in line with the residual balancing incentive. NGG may also consider multi-day offers on the market if this would help alleviate a situation where a Gas Balancing Alert has been declared.

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?

NGG is strongly of the opinion that it operates the system in an economic and efficient manner in accordance with its Licence obligations and the financial incentives under which it operates. We believe a good indicator of this is the strong performance NGG has demonstrated across the various incentive schemes that have resulted in NGG delivering considerable savings to the gas industry and to end consumers.

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

Information gathered through our TBE consultations shows that although historically UKCS flows have been relatively stable through the year and have constituted the majority of flows entering the UK, going forward supply flows are likely to be much more price sensitive as the UK will compete for gas with continental Europe and the global market for LNG. The increasing ability of producers and interconnector pipelines to switch delivery between the UK and continental gas markets in response to price differentials between these markets means that forward or back loading of entry flows is more likely to be seen at some of the large entry terminals within the gas day. In addition, the total supply capability to the UK market has grown at a greater rate than system demand. All of these factors create a very significant increase in uncertainty regarding how the market will choose to exercise their capacity rights going forward, especially as the capacity rights that NGG is obliged to release under its GT Licence each day far exceeds the forecast peak system demands.

Diversity in supply also brings with it issues associated with the gas source. In the context of the current incentives, NGG could face more exposure to CV shrinkage costs due to the capping rules applied where gases of different CVs enter an LDZ. This risk will increase if commercial arrangements to allow supplies to connect directly to GDN systems are implemented.

Another important factor which may impact the effectiveness of the SO in NTS operation is the termination of the SOMSA contracts between the NTS SO and the DNOs. Developments to the NTS exit regime, DN interruption regime and other commercial framework changes with the distribution networks will require the gas DNOs to revise the manner in which they operate their networks. This is likely to have consequences for the operation of the NTS, and may cause NTS operation costs to increase.

The recent Transmission Price Control Review introduced obligations on NGG to facilitate the transfer and trade of NTS entry capacity between ASEPs, in order to prevent sterilisation of capacity and to allow capacity to be moved to where the demand for capacity is greatest. In addition, the ongoing reconsultation on entry capacity baselines may change the level of capacity that NGG is obligated to release each day. We anticipate that such developments in the regime may result in increased system operator costs including those in relation to entry capacity buyback, shrinkage and residual balancing costs.

NGG is implementing a programme to replace some of its gas compressor drives for electric drives that are more efficient and that reduce overall emissions of greenhouse gases to the atmosphere. The operation of these new electric drives will require more electricity to be used, although there will be a reduction in gas used to fuel compressors.

This change in fuel type will mean that, although the cost of procuring shrinkage gas is expected to fall, the costs of procuring shrinkage electricity will increase.

Question 22: Do you consider that the current form of the residual gas balancing incentives is appropriate?

Question 23: Do you believe that the existing linepack incentive has little impact on the behaviour of the SO?

Yes, the current residual gas balancing incentive is appropriate to the secondary role that the SO is required to play in system balancing. This lends itself to a scheme where the SO is required to keep the cost of balancing actions in line with the average market price, and where the SO faces limited exposure to balancing costs. In contrast the electricity SO bears the full costs and risks of balancing actions within its incentive scheme.

The gas price component of this incentive was designed to prevent NGG from overly influencing market prices when managing system imbalances through OCM trades. NGG has historically been able to minimise the effect of balancing actions on gas prices by trading so as not to over influence SAP and only taking balancing actions where necessary. We believe that this part of the incentive has been effective in driving the appropriate SO behaviour in the market.

The linepack component of this incentive was designed to prevent market imbalances from being carried forward to anther gas day, in order than costs could be targeted at the gas day in which they were incurred. It was anticipated that NGG would be able to trade off the requirement to balance the system with the cost of taking balancing actions. There are two main reasons why this element of the incentive may be less effective than the price incentive.

Firstly, NGG are incentivised to manage linepack to within a tight tolerance in order to perform well under this part of the incentive, yet the information required to be able to identify an imbalance to this accuracy is not known until some time into the gas day. This is an example of where NGG is exposed to risks where it is reliant on the quality and timeliness of information provided to it by third parties, including DNOs.

Secondly, NGG operates the system to reduce the costs related over all incentive schemes. Where other incentives interact with the linepack incentive, this may have reduced the scope to maximise performance under the residual gas balancing scheme.

We believe that both components of the incentive are still appropriate to where the primary responsibility for balancing lies with the market, however the parameters of the scheme in relation to the management of linepack should be reviewed to ensure that the incentive is correctly positioned in relation to the other schemes under which NGG operates.

Question 24: Is it still appropriate for the gas shrinkage volume target to be dependent on flows through St Fergus?

Yes, our analysis indicates that St Fergus will continue to contribute a major component of the gas flows into the NTS on any day for the remaining formula period and beyond, and that this is the dominant driver of compression requirements. Further, new supplies of gas may be brought into St Fergus terminal which would offset any decline in UKCS gas. We therefore continue to believe that St Fergus remains a major factor in determining shrinkage gas volumes due to the compression required to transport gas from St Fergus to the centres of demand, and therefore it is appropriate to link the shrinkage target to these flows.

Question 25: Is the current gas cost reference price methodology still appropriate?

NGG believes that the current methodology is still appropriate as it encourages forward procurement of shrinkage gas, and protects the consumer from volatile wholesale prompt gas prices. We believe that the longer term procurement incentive properties of the methodology are still appropriate and that they have been proven to deliver cost savings (when compared to average forward market prices) to the industry and consumers since they were introduced.

It is important that an appropriate GCRP methodology is used which reflects prices over the period when it is efficient for National Grid NTS to manage the risk in relation to its procurement of NTS Shrinkage gas. In addition to this, as this is likely to lead to forward gas procurement, it is important that the methodology is set well ahead of the relevant gas year and that there is certainty regarding the enduring arrangements.

Significant volumes of gas are required for NTS Shrinkage purposes (compared to that procured for distribution networks). The current GCRP methodology is an appropriate enduring methodology to reference the cost of NTS Shrinkage gas since it allows the NTS SO to purchase gas over a longer period offering the opportunity to employ risk management strategies that reduce costs and to avoid affecting market prices by buying large volumes of gas over short timescales.

For the incentive year 08/09 we do not believe it would be appropriate to establish a methodology which uses retrospective prices as this does not fulfil the purpose of the incentive, creates an unmanageable risk on both National Grid NTS and ultimately consumers and may result in a windfall gain or loss depending on how the market has moved since the start of the GCRP period. This would be the case if the current methodology was applied in its current form, or if a 'fixed price' approach was adopted.

We believe the best option is to agree and establish as quickly as possible a GCRP methodology similar to the current one, amended for 08/09 to exclude the period prior to agreement, and extending the reference period relating to the latter half of 08/09 to recover already elapsed procurement opportunity. We believe this could be expedited without detriment to the rest of the review process, by issuing a Section 23 Licence consultation on the GCRP methodology in parallel to the planned SO Incentives Review Initial Proposals document later this year.

Another possibility for the interim period is to design the GCRP methodology to use prices from a fixed period ahead of the delivering month (e.g. 9 months) on a rolling basis e.g. January – September for delivery in October, February –October for delivery in November etc. We believe this is less efficient as an enduring methodology, but could be applied to the incentive year 08/09 given the present circumstances.

Question 26: Is the current form and scope of the gas system reserve incentives still appropriate? Do you consider that the sharing factors, cap and floor for this incentive are still appropriate?

NGG is currently developing arrangements to introduce contestability in the provision of operating margins (system reserve) services. NGG has sought to procure services from new providers in the past, but there has been little or no interest due to the nature of the system requirements that underpin the service definition. There is now increased scope for potential new providers with the new storage developments and demand-side services coming forward in the market. We anticipate that this will require ongoing consultation with the industry and DNOs and management of our Safety Case requirements.

In this context, we believe that a long term system reserve incentive should be set, as it encourages the SO to continue to evaluate system reserve requirements against a changing supply pattern and to continue to focus on reducing the costs of providing operating margins cover to the consumer. In general, we believe that an annual process for agreeing this incentive is ineffective since procurement for operating margins services must necessarily coincide with commercial arrangements for storage operators and therefore must be procured ahead of the start of year in which the incentive is applied.

We recognise that a shorter term solution is required to implement the system reserve incentive for the 2008/9 formula year, and we anticipate that a rollover of the current incentive would therefore be appropriate in this situation, given our duties under our existing Safety Case. However, we consider that it would be inappropriate for the target for the system reserve incentive to be set after NGG initiates the 2008/9 operating margins procurement process, so we urge Ofgem to provide confirmation of the system reserve incentive targets by the end of 2007.

We believe that the current 100% sharing factor is appropriate where the majority of gas is likely to be sourced from price regulated LNG storage facilities owned by National Grid.

The current scheme has no cap or collar. We suggest that sharing factors and caps and collars for this scheme are revised after NGG complete the development of arrangements for contestability in the provision of operating margins services.

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.

NGG is currently undertaking analysis of its OM requirements for 2008/9 based on the information obtained through TBE 2007. The indicative data provided for this consultation paper was intended to show the plausible range of OM that could be forecast for 2008/9, given the assumptions underlying TBE 2006 information. NGG fully expects this information to change, and so the data should not be taken as a forecast of its OM requirement.

NGG procures OM services at the Isle of Grain importation facility due to the requirement to provide system reserve support to London and the South East in the event of specific supply losses or pipe breaks, as described in our Safety Case. NGG have considered alternative providers in the past but have not been able to find other providers that meet the requirements for delivering operating margins services.

As part of our programme of work to develop a fully contestable market for the provision of operating margins services, we have recently issued a tender for South East operating margins requirements that will be open to all shippers in the South East area (including new and existing shippers using the Isle of Grain facility). We anticipate that as new supplies and storage facilities are developed in the future, the locational requirement for operating margins services in the South East will reduce.

Question 28: Would the increased stability of the gas SO incentives schemes of longer duration be preferable to the increased flexibility offered by schemes of a shorter duration?

NGG considers that longer term incentives will be more effective in delivering improvements to operating efficiency, as they incentivise the SO to invest in more innovative solutions that may have a longer payback period than one year. Our experience in operating under the current package of incentives shows that often, cost savings can be made by considering longer term procurement strategies to avoid exposure to short term prices. Longer term incentives also address the issue of setting annual incentive targets after procurement decisions have been made.

However, longer term schemes are by nature more risky compared to a short term scheme. Where external factors that affect incentive cost forecasts are either unknown in advance, or are highly uncertain, it should be possible to identify a set of target drivers that adjust the scheme to respond to changes in drivers. A good example of this is the current form of the gas shrinkage incentive, which is related to the average annual flow through St. Fergus.

Question 29: Are there any aspect of the gas SO incentive schemes that you would consider would be more effective if bundled, rather than remaining in their current form?

NGG believes that bundled schemes with an appropriate risk/reward profile allow the SO to make trade-offs between related cost drivers and tending to bring down overall costs, especially over the longer term.

Historically the separate schemes on gas have not prevented NGG in making these trade-offs between use of compressors, linepack levels and provision of system capability to support entry and exit flows. We consider that it is still appropriate to develop individual schemes where clear cost drivers have been identified that do not interact heavily with other schemes (e.g. the demand forecasting and web-site performance incentives), however the scope for introducing a bundled scheme on gas could be examined to see whether further efficiency trade-offs can be made by a combined scheme.

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 are addressed under an incentive scheme?

Yes, Income Adjusting Events (IAEs) are an appropriate mechanism for managing, ex-post, the potentially high costs of unforeseen or unforeseeable events and, as such, IAEs are similar to ‘force majeur’ provisions in any standard contract.

We note that the majority of respondents to Ofgem’s previous consultations on incentives for 2006/07 electricity incentives agreed that IAEs were an appropriate mechanism. Both National Grid and other parties can raise IAEs. All IAEs are consulted upon by Ofgem, with the Authority having final decision on approval. This gives adequate protection to consumers.

Due to the nature of operation of the transmission system and the governance arrangements, there are many potential incidents and market changes that can significantly influence the costs of system operation that are outside the control or influence of the SO. A method of funding the SO for costs incurred due to such unforeseen events or market change is required and in our view the IAE mechanism is the most appropriate way of meeting this requirement.

Question 31: Do you consider that 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 be able to propose modifications to these Statements?

NGG publishes its System Management Principles Statement and Procurement Guidelines Statement in accordance with the provisions set out in Special Condition C5 of its GT Licence. These statements set out how the SO intends to undertake its activities in a manner which is consistent with its licence obligations and wider statutory duties. NGG as NTS system operator is best place to determine how it intends to fulfil its licence obligations in operating the NTS, and it is not for market participants to propose changes to how NGG operates under the terms of its licence, as doing so could generate windfall gains the industry party wanting to propose the change, or losses to other parties and potentially require NGG to operate the system inefficiently and uneconomically.

The statements are subject to an annual consultation process and there are various industry forums (such as the Ops Forum and Transmission Workstream meetings) where issues may be raised for discussion by the industry. NGG would normally expect to update these statements in line with any UNC modifications made under the UNC governance processes. In addition, NGG is required under its licence to undertake an annual external audit to demonstrate how it has complied with the System Management Principles Statement.