

BWEA Response – National Grid SO Incentives

Dear Malcolm,

BWEA welcomes the opportunity to comment on the formulation of System Operator (SO) incentives.

BWEA's key interests are in:

- the management of constraint and other SO costs,

This is important because the costs are ultimately borne by consumers and so clearly they should be managed in an efficient manner. There has also been a lot of wider industry discussion around the amount of constraint costs that would arise in a Connect and Manage regime.

National Grid's role as SO should be to constantly evolve its practices to keep pace with changes in the energy market. It is important to see costs in the wider context, and in particular to make sure that there is the right balance of costs. A focus on minimising operational costs alone could result in National Grid resisting new connections or generally frustrating new developments unless there can be a trade-off between operational, reinforcement, environmental and other relevant costs.

- the predictability of constraint and other SO costs,

Clearly it is important for National Grid's incentive scheme to accurately predict costs. Market participants also pay the costs and hence predictions are very important for financial planning. A yearly bundled cost does not reflect the timing of BSUoS payments and hence forecasts which better reflect what users pay would be helpful.

Again, if National Grid does not reflect the changing nature of the market in its predictions, then that could result in perverse outcomes.

- incentives on the SO which facilitate the right balance between system balancing and undertaking timely reinforcements, and

We think that this is critical and is to-date lacking in the incentive schemes which frame National Grid's attitudes and actions.

- the impact of variable renewables generation on balancing costs.

Clearly we will take a keen interest in National Grid's view on the system balancing costs of renewables. We accept that there will be some costs and that this part of the progression towards a low carbon energy mix. It is important to put these costs in context, and to ensure that National Grid is on the cutting edge of practices that aid integration of variable renewables. We would urge caution in presenting preliminary analysis as this could be taken out of context. We would also ask that analysis is fully referenced and clearly presented, and that views come with reasoned justification.

The remainder of this response considers areas of the consultation document that are relevant to these four key issues.

Management of constraint costs

BWEA accepts that it is challenging for National Grid as SO to influence and control all constraint costs. We do not, though, think that this should in principle be any more difficult than managing other system costs which are also subject to market-based procurement.

Reliance on resolving constraints through the short timescales of the Balancing Mechanism (BM) seems to make costs more difficult to predict, and so the obvious answer is to rely more on longer-term contracts. This kind of shift would make sense where more use is being extracted from existing assets under a Connect and Manage regime (C&M) with an inevitable increase in the use of balancing actions and / or negotiated access restrictions.

The consultation also hints at generator choice over outage periods being problematic in so far as plans can change at any time with no come-back for the generator on the consequent constraint cost implications. This is unlikely to be black and white and there may be good reasons for this, but if it is agreed that it is correct for National Grid to have no control over generator outages, then it stands to reason that National Grid should not be exposed to the consequences.

It would be useful to understand the materiality of these kind of factors on constraint costs – for instance the variability of wind is cited as a driver of constraint costs, but the unpredictability of generator outages is not. Nonetheless National Grid says it cannot produce a forecast of constraint costs, and it wishes not to be exposed to constraint costs, because, *inter alia*, it has no control over generator outages. Either it is an important cost driver or it isn't. If it is, it should be quantified. If it isn't, it should not be relevant to the incentive scheme and the production of a forecast.

The consultation also says that Locational BSUoS should improve the co-ordination of generator and transmission system outages. The implication is that generators are taking outages when they like because they are not exposed to constraint costs as they occur. If there are good reasons for generators to have a free choice over outage timing, then we see no reason why locational BSUoS should be allowed to change this. If there are not, and National Grid would prefer generators to take outages in line with transmission outages, then surely there are other routes which can be explored – Locational BSUoS is a rather extreme measure to take for this issue.

Constraint cost predictions

The consultation highlights that SO costs have been above forecast costs under the incentive scheme since BETTA, when previously they were below. This raises the question of whether the Scottish TO's should have some more buy-in over constraint costs and their management – perhaps through helping National Grid in predicting the costs.

BWEA understands why National Grid is suggesting unbundling of constraint costs, but we do not agree that options have been exhausted to manage and control the costs. Ofgem has stated that unbundled schemes may be appropriate “*in the case of low interactions with other costs and activities*” but that it supports a bundled scheme “*where there is uncertainty regarding the interactions with the SO's other costs.*” We take this to mean that because there is difficulty in unravelling SO cost drivers, it is better to mask this by lumping it all together. BWEA would note nonetheless that Ofgem has said that it sees merit in Locational BSUoS, which attempts to take out and apportion certain SO costs. These two arguments are inconsistent – either costs can be unbundled or they cannot. We are very disappointed that Ofgem's arguments change depending on the context.

BWEA does not have a strong view on whether costs should be bundled or unbundled but agrees with Ofgem that there is strong interactivity with the various components of the SO's costs.

BWEA supports the provision of a longer-term view on SO costs as this is useful market information. We do not as yet have a strong position on whether the SO's incentive scheme should stretch to two years or more.

Even though there is no two-year forecast of constraints in this consultation, there are various studies which draw heavily on National Grid's expertise, which forecast constraint costs much further out. This includes work by Ofgem's own consultants. The wide range of costs makes it clear that the costs are very much dependent on the inputs and assumptions.

Therefore we feel any effort henceforth would be better spent on establishing the relationships between key inputs and out-turn costs, rather than on generating any more absolute out-turn numbers, of which there are many, with a very large range. This would inform whether the incentive scheme should be indexed to any key variables. It would also help market participants come to their own view on constraint costs.

Question 8 asks about the growth in wind energy which is used as an input variable for predicting SO costs. National Grid uses the contracted background which may be reasonable looking a year ahead but perhaps less reliable further out with the ongoing changes in the access regime. National Grid could take a much more sophisticated approach to predicting connection dates and plant output by gathering more intelligence on the progress of projects and predicting output based on recognised industry tools.

The balance between SO costs and system reinforcement

We note that rising constraint costs is a clear signal on the need for system reinforcement. At present this signal does not prompt reinforcement, and National Grid's proposal to alter the allocation of constraint costs – Locational BSUoS – serves to minimise costs through discouraging connection and generation rather than to use it to encourage reinforcement. We would much prefer to see incentives which fed directly into reinforcement decisions.

Variable generation and SO costs

The consultation is a little contradictory on the link between variability and system balancing costs. It implies in places that extra wind on the system will increase balancing costs because of its variability but then later notes that any extra balancing costs predicted are due to extra generation *per se*, flexible or variable.

Furthermore, there is clearly a price attached to making fossil thermal generation predictable and flexible when the market allows it to behave unpredictably and flex its output as it likes, rather than as the SO would like. Variable output which is in line with a renewable resource is potentially more predictable than market-based decisions of thermal generators. The consultation does not really distinguish between costs for what is variable but predictable, and what is variable, flexible (responsive to market signals) but unpredictable.

For instance there is a discussion about a variable Net Imbalance Volume (NIV) as wind increases its penetration, and an assumption that this will be inherently unpredictable. However as wind penetration increases one would expect predictive tools to develop alongside and for National Grid to adapt itself to the new conditions, thus managing and mitigating costs. Variability does not always equate to unpredictability.

The consultation also tends to attribute costs to individual technologies rather than to a combination of, say, variable wind, inflexible nuclear and changes in the operating regimes of flexible plant.

Furthermore the discussion around wind energy and market length in Section 3 is quite confusing. National Grid talks about “*spill*” onto the system being uncontracted energy. However all wind-generated electricity generated onto the system is contracted to a supplier – if it weren’t it would not earn its Renewable Obligation Certificates (ROCs).

NIV is described in the consultation as the sum of balancing actions in “*operational timescales*.” As balancing actions are taken against grid code notifications rather than BSC notified positions, it is difficult to understand what National Grid means in this context by “*uncontracted*” in any sense. Even the BSC notifications are somewhat artificial in setting a gate closure time and a need to contract ahead when this does not reflect the diversity of contract structures which are layered underneath these notifications.

As a result of this confusion it is very difficult to understand what the consultation actually means when it is talking about market length. What are the timescales? What is the spill that makes it longer? What are the contracts that National Grid refers to when it talks about NIV becoming more variable if wind energy did contract rather than spill? We would be happy to provide further input on this subject to some clarification on these points.

BWEA accepts that more wind on the system can be expected to impact on system balancing costs. We would urge National Grid to give some very careful consideration to what kind of information it would like from wind energy plant, and how best to procure this. There seems little value in a cash out regime that penalises wind for not accurately predicting its output a half hour ahead of real time when National Grid doesn’t even use the BSC contract notifications.

Similarly there seems little value in an information imbalance charge on grid code notifications which penalises wind farms for not being able to do what they can’t do. In any circumstance where the market asks for information that is unrealistic, National Grid would simply use its own forecasts and discard what the market was telling it. It therefore would seem more useful to collaborate with the wind energy community in procuring useful information that would best help National Grid balance the system. BWEA would be happy to participate in any such initiative.

BWEA cannot comment on the lack of a relationship between NIV and extra wind on the system, because we do not fully understand what NIV is counting. However we would note that a good proportion of wind is lost in the variability of demand, and furthermore that all the evidence suggests that wind is predictable to a degree, and especially so for forecasts that aggregate geographically dispersed wind farms.

Looking forward we would urge National Grid to consider profiling for variable resources that are dispersed throughout the distribution networks, similar to demand profiling. This may be particularly useful to prepare for the inevitable rise in distributed small schemes stimulated by next year’s Feed in Tariff for projects up to 5MW in size.