James Curtin Commission for Energy Regulation The Exchange Belgard Square North Tallaght Dublin 24	Brian Mulhern Utility Regulator Queens House 14 Queen Street Belfast BT1 6ED

18th November 2016

RE: Offers in the I-SEM Balancing Market ('the Consultation Paper')

Dear James, Brian,

Bord Gáis Energy ("BGE") fully supports the Regulatory Authorities' ("the RAs") objective to implement a set of regulatory bidding controls in the balancing market as a means of mitigating market power in the 'constrained' or 'non-energy' side of this market.

However, BGE asks that the RAs note and recognise that within the constrained market there are 2 types of participants; a) those units behind an export constraint that hold local market power on the basis that they know they are 'must run' units, and b) those units that compete to provide ancillary services (i.e. reserve) for the TSOs and who are constrained up and down by the TSO to provide the requested reserve and earn the requisite ancillary service revenues. There are some in this second tranche of units who may actually have market power where there is no competition in the provision of certain services or reserve, and essentially these units would in essence hold a similar type of market power to those in the first tranche.

The competitive incentives and opportunity costs of these types of units can be quite different and BGE is concerned that prescriptive 'Offer Principles' (i.e. Option 1 in the Consultation Paper) that limit allowable opportunity costs may not be appropriate for those units operating in a competitive environment.

Although the proposed 'Offer Limit' option (i.e. Option 2 in the Consultation Paper) may provide for more flexibility to distinguish between the two types of non-energy providing units referred to above, BGE does not believe that it would be an appropriate market power mitigation tool for the first tranche of units who hold market power. In our view, it would allow some of those units to bid beyond their Short Run Marginal Cost (SRMC) and to earn excessive Infra-Marginal Rent (IMR), thus re-enforcing their market power. Furthermore, as a regulatory tool in and of itself, BGE would also suggest that it is too intrusive a measure both in terms of regulatory burden to constantly monitor and change the Offer Limit in line with market fundamentals and in terms of essentially setting a target price in the market for those who hold market power.

On that basis and on a principled level, BGE supports an 'Offer Principles' approach to regulating market power in the non-energy balancing market. However, BGE has a number of concerns relating to the specifics of the 'Balancing Market Offer Principles' (BMOP) Code of Practice outlined in Annex A of the Consultation Paper. Recognising firstly; that the Bidding Code of Practice currently in place in the Single Electricity Market ('the SEM') aimed at striking a balance between sufficient guidance to parties in compiling their bids into the market while allowing flexibility in bids to enable competitive and innovative bidding strategies, and secondly; that this flexibility to promote competition may not be appropriate for those holding local market power, we are still concerned that the targeted/prescriptive approach may have unintended consequences for other participants that do not hold market power and who are operating in the non-energy market.

We outline our thoughts and comments on the specific BMOP proposals in the sections below.

1. Redefining SRMC

The current Bidding Code of Practice (BCOP) effectively estimates marginal costs by comparing the costs of generating electricity during **the trading day**, with the hypothetical costs of not operating that day. As identified in the Consultation Paper, this calculation doesn't really reflect which costs are likely to vary in response to a balancing market action and is therefore unlikely to capture the genuine cost implications of, for example, incrementally increasing a unit's output.

The Consultation Paper therefore considers moving to a more granular definition of the SRMC, for example linked to the relevant Imbalance Settlement Period. The proposed drafting also suggests that the SRMC should reflect the costs of increasing or reducing output by a single MWh during the relevant Imbalance Settlement Period.

We agree that the current definition of SRMC is poorly aligned with the actual cost implications of balancing market actions and that a more cost-reflective definition would account for the more granular nature of such decisions, and specifically within an Imbalance Settlement Period.

In terms of accurately reflecting generators' costs, we note that the SRMC definition proposed considers increments of 1 MWh, but that generators will submit up to 10 price-quantity pairs under complex offers for different amounts of energy. Therefore, we would propose that the cost metric used to define appropriate incremental costs instead be defined in terms of the incremental cost associated with altering output as specified in **the relevant offer**. In the case of energy offers, this will imply the incremental costs of increasing or decreasing output **by the specified volume** for the **specified Imbalance Settlement Period**.

This approach will be ideally cost-reflective, since it accounts for the fact that the costs defined over a 1 MWh increment or decrement may not hold uniformly when a generator varies output by a different volume.

2. Redefining Opportunity Costs

In outlining the approach to valuing "eligible cost items", the proposed BMOP states that "eligible cost items shall be valued at their opportunity cost" and then goes on to state that in calculating the opportunity cost of the benefit forgone in employing the eligible cost item a reference price to a distinct market price or contract price must be used and provided.

This approach in BGE's view overlooks two important points when it comes to the consideration and derivation of opportunity costs.

Firstly, section IV of the proposed BMOP outlines **the specific costs** that are eligible for inclusion in Balancing Market complex bids, being incremental fuel costs; incremental operating costs; incremental emissions costs and specific costs relating to start-up and no-load. In being so prescriptive, the proposed principles move away from an economic concept of opportunity cost and instead employs' an accounting approach to building up relevant costs. This accounting based approach overlooks the other real economic costs or 'alternative options' that a business must consider when deciding to invest in energy generation and the trade-offs that must be considered by the owners of such units when considering the operation of a unit.

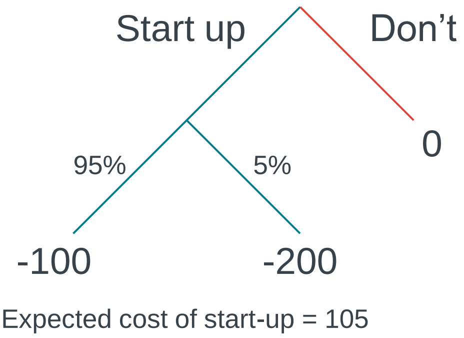
For example, the proposed BMOP excludes some key cost items for generators such as maintenance costs. The consultation claims that all maintenance costs are fixed, since maintenance is scheduled periodically and, implicitly, that maintenance costs are not affected by dispatch behaviour. In terms of economic theory, all that matters is whether the relevant costs vary as a result of the Balancing Market action (e.g. changing output, or starting up). In reality, running hours and cycling patterns affect a units' maintenance timelines and costs. For example, a unit can be contractually obliged to come out of service for routine maintenance after a set number of fired hours or depending on cycling patterns. Although the prices for these maintenance schedules may be agreed in advance as part of the contractual negotiations, the actual cost for a specific unit will depend on the physical running of the unit. To the extent that dispatch instructions and/or cycling increases wear on the unit and this requires maintenance, the variable maintenance costs cannot be deemed to be zero and should be considered an eligible cost for the purposes of representing the true marginal costs of Balancing Market actions.

BGE believes that in being so prescriptive, the BMOP is not allowing parties to recover all legitimate costs related to operating a generation unit in the Balancing Market and therefore is in danger of breaching one of the RAs' statutory obligations to ensure that generators are appropriately compensated for making available generation sets or units.

Secondly, in Section V, where the proposed BMOP sets out the principles to be applied in valuing the 'eligible cost items' at their opportunity cost, the provisions in the current BCOP relating to "reasonable provisions for the increased risks to plant and equipment as a result of the operation of a generation set or unit" have been removed. The Consultation Paper suggests removing this provision on the basis that it "does not represent a benefit foregone and is arguably being added on top of the standard definition of opportunity cost". The Consultation Paper also proposes to remove the provision relating to revenues foregone.

On both of these exclusions, BGE believes that the proposed BMOP is misrepresenting what costs are relevant for generation units from an economic perspective. To put this in context, to the extent that resources, such as working capital or staffing are required to manage a risk or reduce a cost and these resources could be redeployed elsewhere, there is a clear economic cost or opportunity cost associated with undertaking higher risk actions or reducing costs. Specifically with reference to risk, take the stylized example below. In this case the generator is considering whether or not to accept a payment to start up. If it does nothing, it incurs no costs. If it starts up, there is a 95% chance it will incur costs of 100 and a 5% chance that there is an equipment failure and it incurs a cost of 200.

Exhibit 1. Stylised example of costs with risky start-up



Imagine that we ignore the risk the plant is taking and offer it 101 to start up, slightly more than the generator's cost under normal circumstances. A rational plant operator will understand that its expected costs are actually 105 (i.e. a 5% probability of an additional 100 cost) due to the risk involved and therefore choose not to start up. What's critically important is whether or not these differences in risk affect generators' assessment of the different 'opportunities' available. If they do, then failure to account for them risks a system where bids based on the BMOP are insufficient for generators to willingly provide compliant Balancing Market offers.

Related to the above point, the consultation document also proposes to exclude the cost of foregone revenues. While we acknowledge the practical difficulty in evaluating the size of potential future revenues, it remains the case that where an action puts future profits at risk, rational generators will inevitably factor this into their assessment of the options available e.g. foregone ancillary service revenues where a peaking unit is constrained on or a part-load plant is constrained up. A failure to account for this impact will imply that BMOP bids do not match the true value of other opportunities. Ultimately, the reality of dispatch decisions is that there are causal links between dispatch decisions now and the opportunities available to generators in future periods that cannot be removed by amendments to the BMOP, but which could, if ignored, result in administrative bid levels that generators would not willingly submit.

In conclusion therefore, excluding risks and foregone revenues does not make sense in an opportunity costs framework and may result in bidding principles under which generators would expect to make a loss from having an offer accepted. With respect to the RAs' concerns about double counting for risks or evaluating the value of revenues foregone, this is something that we think can be reasonably managed by a well resourced Market Monitoring Unit as it is now and we do not think that this administrative difficulty is sufficient to warrant the exclusion of legitimate costs outright. We also note that the draft BMOP text already includes provision for the use of futures prices when considering the bids of energy-, emissions- and time-limited units. Although the trade-offs among different time windows are perhaps most obvious for such units, they are also relevant for generators of all types. As a result, generators' bids will need to reflect this fact if generators are to be incentivised to participate.

3. Eligible Cost Items

As outlined in section 2 above, BGE is concerned that the proposed BMOP is overly prescriptive in how it provides for eligible cost items within the non-energy Balancing Market. In being prescriptive, the proposed BMOP overlooks some legitimate costs, such as maintenance costs but also potentially over-states the marginal cost of others such as Gas Transportation Costs. The proposed BMOP provides for Gas Transportation Costs to be included within bids at one of 2 cost levels – i.e. gas fired generators bidding into the balancing market are obliged to include these costs in one of two forms. It is not clear that such costs would automatically or always vary in response to Balancing Market actions. Therefore in being so prescriptive as to what 'shall' be included in bids, the BMOP is at risk of providing a rule-set as opposed to a set of principles and whereby we are concerned that this rule-set may exclude certain costs leading to under-recovery, it could also incorrectly provide for certain other costs that may not be legitimate variable costs for some units or in certain instances.

This in our view, further highlights the downside of the overly prescriptive approach proposed in the BMOP.

4. Summary & Conclusion

BGE supports the RAs initiative to provide some form of regulatory oversight in the Balancing Market to mitigate market power in the provision of non-energy services. BGE does not believe that the 'Offer Limit' option would be appropriate for the market in terms of being sufficiently effective or targeted to mitigate market power and its effects on competition and customer costs. Our preference would be for a form of 'Offer Principles' to be applied. However, bearing in mind BGE's concerns outlined above we would suggest that a more nuanced approach to the provision of a set of 'Offer Principles'. Two potential options may be either:

a) To provide a flexible set of bidding principles as per the current BCOP which applies to all parties but where 'must run' units – identified through the capacity auction process – are mandated to submit their approach to deriving opportunity costs and the inputs to their bids to the RAs for approval before entering their bids into the Balancing Market (this would not be required for each day, but only at the point of market go-live and any point there after where the party looks to change their approach for a specific unit). This would ensure that those units with identifiable market power are subject to appropriate regulatory scrutiny while allowing other parties, who do not hold market power and who are competing to provide ancillary services, freedom to submit innovative bids which reflect the true opportunity costs of operating in a competitive market; or
b) To provide a prescriptive set of bidding rules but apply this rule-set only to those parties identified as having market power in the Balancing Market – again perhaps by reference to those 'must run' units identified as part of the capacity auction process.

Either of these more nuanced approaches would in our view be better aligned with the principles for market power mitigation outlined as part of the Market Power Decision Paper (SEM-16-024). They would be targeted and effective in ensuring that those with Market Power face appropriate regulatory constraints while being equally flexible, practical and transparent such that they do not hamper the ability of those units who do not hold market power from competing effectively through innovative bidding strategies.

To the extent that the RAs are concerned that a flexible set of bidding principles will give rise to extra administrative burden in the form of investigations and challenges, the experience in the SEM to-date shows that with familiarity and good governance the level of uncertainty reduces over time and therefore so too the administrative burden. Although there were a number of investigations in the early stages of the SEM, these have greatly reduced in recent years given the precedence provided by these publically consulted investigations. With that in mind, BGE does not believe that there will be a significant administrative burden and this burden would be reduced the closer the BMOP resembles the existing BCOP with which parties are already familiar with.

Regardless of which option is applied, BGE urges the RAs to review their proposed Offer Principles approach to identifying 'eligible costs' and ensure that all parties have comfort and certainty that they will recover all reasonable and legitimate opportunity costs relating to dispatch decisions taken in the Balancing Market.

Lastly, with respect to the interaction between these principles and the Capacity market, BGE is currently reviewing the Capacity Market Parameters Consultation (SEM-16-073) and would welcome an opportunity to discuss our thoughts on how it interacts with this Consultation Paper at a future point in time once we have had the time to consider it in full. Likewise, with respect to the Ancillary Service market, at this stage we do not have enough information with respect to the form and competitive structure of this market to understand how it too may interact and impact on opportunity costs relating to the Balancing Market. We will consider this further as information relating to the level of competition in the Ancillary Service market becomes available, which is currently expected in Q1 2017.

I hope that you find the above comments and suggestions helpful to your considerations. Should you have any questions or wish to discuss any of the above in more detail please do not hesitate to contact me.

Yours sincerely,

Jill Murray
Bord Gáis Energy

{By email}