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Brian Mulhern
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Commission for Energy Regulation, Dublin

Submitted by email

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Dear Mr Mulhern & Mr Quinn,

Submission on the detailed design of the capacity remuneration mechanism (SEM-15-044)

EnerNOC is grateful for the opportunity to respond to the consultation paper released last month. We welcome the open and consultative manner in which these design issues are being addressed: adopting a flawed market design would be highly damaging, so careful analysis is warranted.

EnerNOC provides energy intelligence software and services to commercial and industrial energy users and to utilities. As well as helping users manage their energy usage and costs, we work with them to offer their demand-side flexibility into wholesale capacity, energy, and ancillary services markets and utility programmes. We have experience of doing this in eleven countries, under a very wide range of market designs.

We agree with the Single Electricity Market (SEM) Committee that smaller systems and high levels of renewable generation put market designs under much more stress.[1] We agree that central auctions and central settlement are the most efficient approach, and provide the highest level of transparency.

Our comments below follow the structure of the consultation paper. Our principal concerns are risk, product design, and eligibility.

1 Assessment criteria

We agree with the assessment criteria, particularly the competition and equity criteria.[2]

The equity criterion calls for the fair and reasonable allocation of "costs and benefits". We would add that risks should also be allocated in a fair and reasonable manner, and should be no larger than necessary to incentivise efficient investment and operation.

[1] Consultation paper, p. 9.

[2] *Ibid.*, p. 16.

This "risk criterion" is important because it is easy to come up with a design that leaves some or all participants with unmanageable risks. If the risks are unfairly allocated, then they will hamper those participants who are most exposed, distort market outcomes, and result in less competitive outcomes. If the risks are higher than necessary, then the costs of managing the risks will be baked into prices, leading to consumers paying over the odds.

2 Product design

2.1 Strike price

§3.2.2 of the consultation paper highlights a key issue for demand-side participants:

> *In general, the [strike price] should be set sufficiently high that difference payments are only made when all available capacity is required. If it is set too low, there is a risk that some high merit order plant may be exposed to making difference payments at a point when it is still out-of-merit, and will not be earning any compensating energy payments.*[3]

Demand-side units (DSUs) are a highly cost-effective source of capacity, but an expensive source of energy. This is because, when dispatched, participating customers must forgo or reschedule their normal business activities. The opportunity costs associated with these actions can be significantly higher than generators' fuel costs.

Exposing DSUs to difference payments when the market price is still below their opportunity costs would violate the risk criterion, as it would be a risk that could not be managed, so would simply be priced in to capacity offers, reducing the effectiveness of competition and increasing costs for consumers.

Similarly, requiring DSUs to be dispatched out-of-merit would violate the efficiency criterion.

As discussed during the workshop on 31 July 2015, assuming that the energy market is reasonably competitive, the consequences of setting the strike price too high are far less severe than those of setting it too low. We would therefore recommend that the strike price be set well above the short-run marginal costs of any current DSUs.

The current Bidding Code of Practice requires DSUs to offer their energy at their short-run marginal cost, so these costs are known: they are typically in the range €300/MWh to €390/MWh. However, as the market matures, it may make economic sense to source capacity from customers with higher opportunity costs still, so some headroom should be provided.

[3] *Ibid.*, p. 29.

2.2 *Market reference price*

We agree that it is crucial that all capacity providers should be able to access the market reference price[4] – i.e. all capacity providers should be able to offer their available capacity such that they will earn the market reference price if the strike price is exceeded. Otherwise the basis risk will lead to violation of the risk criterion: affected capacity providers will be faced with an unmanageable risk, the costs of which they will simply add in to their capacity offer prices.

The guiding principle is that a capacity provider should not be exposed to difference payments which exceed its energy market revenues so long as:

(a) the provider has made the required volume of capacity available for dispatch during each period of scarcity; and

(b) the provider fully responds to dispatch instructions.

This means that the interaction between market offers and dispatch is important, as well as the choice of market reference price.

It is also desirable that capacity providers should not need to distort their energy market bidding behaviour to avoid basis risk.

Given these considerations, Option 4b, the split market price, seems the most promising approach.

2.3 *Load following obligation*

We agree that reliability option obligations should be scaled down pro-rata in the manner described, for three main reasons:

(a) Otherwise, suppliers will be over-hedged during most scarcity events, such that they face a negative effective price, which is perverse.

(b) It avoids violating the risk criterion: if capacity providers in aggregate were required to fund difference payments for a greater volume of energy than they were supplying, this would be an unmanageable risk, which they would simply have to allow for in the prices of their capacity offers.

(c) It allows participation by a wider range of customers: if the same obligation applied even at times of low demand, participation in DSUs would largely be restricted to loads with 24x7 operation. Limiting participation in this way would lead to less competitive outcomes and increase the quantity of generating capacity that would need to be acquired.

2.4 *Performance incentives*

We agree with §3.9.24:

[4] *Ibid.*, pp. 35-36.

> *Ideally all eligible capacity providers should face the same performance incentive regime including requirement to pay difference payments, and any additional performance incentives for under or over delivery of physical capacity at times of system stress.*[5]

Great care must be taken to ensure that any common performance incentive regime is geared to the actual needs of the system, rather than to the capabilities of one specific technology. Otherwise, capacity providers using different technologies will be exposed to increased risks, violating the risk criterion, reducing competition, and increasing costs borne by consumers.

If a workable technology-neutral performance incentive regime cannot be developed, then it may be necessary to develop separate schemes for different technologies. The guiding principle is the same as for the market reference price: providers should be incentivised to make their capacity available whenever needed and to deliver what the system operator requests from them.

3 Eligibility

3.1 Energy payments for demand-side units

This issue is crucial, and has not yet been properly considered.

The discussion in §4.7 of the consultation paper misses a key point: customers consume energy for a reason.

For example, an industrial customer may consume energy so that they can manufacture a product. If the customer didn't place more value on consuming the energy than they are being charged for it, they wouldn't consume it. If they stop consuming energy in response to a dispatch instruction, they forgo the benefit – e.g. they make less of their product. These foregone benefits are a direct cost of providing demand response, just as fuel and variable operations and maintenance costs are direct costs for a generator to provide an equivalent service.

The worked examples in the discussion paper omit these opportunity costs. This is akin to omitting fuel and variable maintenance costs when modelling a generator.

This leads to the nonsensical suggestion that the customer benefits by avoiding making an energy payment for the energy they don't consume. This line of reasoning implies that the customer would be best off if they never consumed.

As mentioned above, the customer must derive greater benefit from consuming the energy than they pay for it, so the opportunity costs from foregone consumption will exceed the costs of the energy. At most, you could say that the customer's loss of utility from reducing consumption is *partly* offset by not having to pay for the energy that they don't consume.

5 *Ibid.*, p. 52.

If scarcity pricing is being considered, then we would suggest that, when the worked examples are re-done, a near-VoLL price should be used as the market reference price. This will make the incentives and risks faced by participants much clearer, as difference payments will be more than an order of magnitude higher than opportunity costs and supply contract prices.

It is also suggested in the consultation paper that some options may be made to work if the customer's supply contract price is indexed to the wholesale spot price. Very few customers do this. Generally, only the largest, most sophisticated customers are able to cope with the resulting risks. Such arrangements must not be made a precondition for demand-side participation, as this is too high a barrier, which will result in inefficiently low levels of participation.

§4.7.7 of the consultation paper suggests that Options 2 and 3 are intended to "improve the competitive position of DSUs" relative to Option 1.[6] In the light of the above, we would put it more strongly: Options 2 and 3 make participation by DSUs possible; Option 1 prevents participation.

Specifically:

- Under **Option 1**, it makes no difference to a demand-side participant's financial position whether they perform perfectly during a scarcity event, or not at all. There is no point in an aggregator paying customers to reduce consumption, as delivering on the capacity obligation does not result in any revenue to cover the difference payments. In extremis, with scarcity pricing, an extended scarcity event will simply lead to all DSU proponents going bust.

- **Option 2**, in which DSUs earn spot market revenue when they curtail consumption in response to a dispatch instruction, and so are able to pay difference payments, is the only approach which is consistent with the principles of equal treatment spelled out in §3.9.24. These spot market funds must come from somewhere. This problem has been solved in a variety of ways in different jurisdictions. Arguably the cleanest approach is for the bulk of the funds to be recovered from each participating customer's supplier, who would otherwise have a windfall gain due to unexpectedly reduced consumption at a time of high prices. However, this may be complex to implement. A more common approach is to recover these relatively small costs through a broader levy.

- **Option 3** is the simplest of the workable approaches. It does not require changes to spot market settlement, but it does require the development of a separate regime of incentives and penalties to provide strong encouragement for DSUs to (a) be available at times of system stress, and (b) deliver in accordance with dispatch instructions.

[6] *Ibid.*, p. 66.

Option 1 is completely unworkable. In our view, Option 2 is the cleanest approach. However, it may be quite challenging to develop in the time available. If Option 2 cannot be implemented quickly enough, then Option 3 is a pragmatic choice.

3.2 *De-rating*

We understand the idea of de-rating, and the approach of using historic forced outage rates for the relevant technologies makes sense. However, demand response is not like generation. It has no intrinsic forced outage rate. Rather, the performance of demand-side participants is a result of the specific programme rules under which they operate. A programme with a different incentive/penalty regime will have different performance outcomes.

The GB Capacity Market has erred here, by using performance in an unrelated programme with very different rules to derive a de-rating value for demand-side participants.

When assembling a portfolio of customer loads to make up a DSU to meet a capacity obligation, an aggregator will never offer the full "nameplate" capacity. Rather, the aggregator will carefully consider the availability, reliability, and limitations of the individual loads, relative to the programme requirements. This is a much more sophisticated approach than a blanket de-rating. In our view, if the penalties for underperformance are stringent, then there should be no need to impose a blanket de-rating on aggregated DSUs. Doing so would only reduce the aggregator's flexibility in assembling a portfolio, and hence increase costs without necessarily improving reliability.

3.3 *Treatment of aggregators*

The discussion in §4.10 of the consultation paper[7] appears to consider only generator aggregators. However, the question of evidence of physical backing could also be relevant to aggregated DSUs.

Customers do not participate in DSUs as their core business. Rather, it is incidental to their main business. Their main business takes priority. For example, if a manufacturer decides to upgrade their plant to halve their energy consumption, they will do so, even though it will reduce the amount of capacity they are able to deliver to the DSU. Similarly, if a customer wishes to close down a plant due to changing market conditions, they will do so regardless of their obligations to the DSU.

To ensure a DSU can continue to deliver its capacity reliably, an effective aggregator will actively manage its portfolio, adding and removing customers as necessary. It is essential that aggregators are allowed to do this – it is analogous to routine maintenance of generation plant.

[7] *Ibid.*, pp. 75-76.

If aggregators are to be required to prove that they have physical backing adequate to meet their capacity obligation, then the regime must allow for customer sites to be added and removed as necessary both before and during the contract's delivery period.

I would be happy to provide further detail on these comments, if that would be helpful.

Yours sincerely,

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