The Association for
Decentralised Energy

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Bringing Energy
Together

Ofgem Consultation - Capacity Market 5-year review | 28 May 2019

Introduction

The ADE welcomes the opportunity to respond to Ofgem's consultation on the 5-year review.

The ADE is the UK's leading decentralised energy advocate, focussed on creating a more cost effective, efficient and user-led energy system. The ADE has more than 160 members active across a range of technologies, they include both the providers and the users of energy equipment and services. Our members have particular expertise in heat networks, combined heat and power, demand side energy services including demand response and storage, and energy efficiency.

Question 1: Do you have any views on the interactions between the CM and other wholesale markets; such as forward markets, the balancing market, and markets for ancillary services?

For decentralised energy, it is essential to be able to stack revenues across the Capacity Market and other wholesale markets.

There remain cases where this is not possible as a result of both the Regulations and Rules. This includes, for example, cases where assets on a site with flexibility suited to the Capacity Market do not overlap exactly with the assets on that site more suited to faster products such as frequency response.

Question 2: Do you have any evidence that design choices in the CM are driving inefficient outcomes in other markets?

There are clear differences in the guaranteed revenue available from the Capacity Market for new generation and DSR respectively. This may create the knock-on effect of giving new generation a competitive advantage in other markets.

As stated in this consultation document, there is significant ambiguity currently across the Regulations and the Rules regarding the eligibility of non-exporting CHP. This was raised by several Capacity Market rule changes last year but none were progressed. At present, the Regulations explicitly include 'exporting onto the distribution network' within the definition of a non-CRMS Unit. When reviewing rule change proposals on this issue, Ofgem felt that this meant that any rule changes to resolve this ambiguity would create a contradiction between the Regulations and the Rules.

Question 3: Do you have suggestions for how these markets can be better aligned and how any inefficiencies can be mitigated?

Regarding the ambiguity over non-exporting CHP, BEIS should use its 5-year review to revise the Regulations' definition of a non-CRMS unit to enable Ofgem to make the changes needed to the Rules to resolve this ambiguity.

Through BEIS' 5-year review, several areas of the CM design are under review to better support the participation of decentralised energy. Ofgem's 5-year review should align with this review.

Further, the current wording of the legal text for modification Of12 regarding component re-allocation is ambiguous. We understand that the policy intent is to set the limits on components and notifications by CMU. However, the use of 'capacity provider' is ambiguous and could be interpreted as meaning that these limits apply to the company participating, rather than the CMU. We propose that this is remedied by adding 'per CMU' at the end of the text to ensure the policy intent is clear.

Question 4: Do you have any views on whether the proposed membership of the CM Advisory Group is appropriate, the form of participation from industry, along with any further points regarding meeting frequency and function?

We support the inclusion of Ofgem, NGESO, BEIS and ESC as part of the CM Advisory Group.

It is important that the industry-nominated parties comprising the remainder of the Group do represent the full spectrum of CM participants. A significant issue in other industry codes is the lack of, or significant under-representation from, non-traditional participants in the energy system. It is important that this is not repeated in the new CM Advisory Group.

In other industry codes, Panels are comprised of industry experts who review how far the changes are expected to constitute an improvement on the status quo against the Code's objectives. They are not representatives of their respective organisations. We consider that there are advantages and disadvantages to this approach. However, on balance, we consider that it would be preferable that the industry-nominated parties are explicitly representative of a group of CM participants to ensure that the full spectrum of participants is recognised equally.

Question 5: Do you believe the proposed framework and function of the CM Advisory Group is appropriate and would better facilitate the efficient operation of the CM Rules change process?

We agree with the proposed framework and function; noting the significant further work required to develop this in detail.

More specifically, we agree that Ofgem should retain the final decision regarding whether a CM rule change progresses. We also support the proposal for the CM Advisory Group to publish an 18-month forward plan to help participants better understand likely future changes.

Question 6: Do you have any feedback on our proposal to move to an 18-month implementation timescale; consulting on rule amendments which would subsequently be implemented the following Delivery Year?

We support this proposal.

The introduction of Of12 component re-allocation was first proposed in 2014. It will only be introduced this delivery year, in part, because of the difficulty in committing to such a significant IT upgrade within the annual CM auction cycle. We consider that moving to an 18-month implementation timescale would better support similar changes in future.

Further, we agree that the current process creates a very short window in which participants can put forward and review change proposals. Moving to a longer change process and decoupling it from the auction cycle should allow more considered proposals and more effective scrutiny.

Finally, we would also note that the current change process creates particular difficulties for CM participants who are the Dispatch Controller but not the Legal Owner; as is often the case with DSR participants. In these cases, applications can sometimes only start with customers once the change process is closed and the Rules finalised. This often means there is a very short time period between finalising the Rules and the start of the pre-qualification window for such applications to start.

Regarding the treatment of urgent change proposals, we support their use but would ask that Ofgem set out clearer and stricter criteria for what should be considered as urgent.

Question 7: Do you have any views on the proposed process, the implications of the change to the Prequalification procedure and whether it would be a positive change in removing an administrative burden?

We strongly support allowing existing CMU participants to roll over their application year on year.

We would also ask Ofgem to consider changes to the rules regarding Director's signatures. In cases where the Legal Owner and Dispatch Controller are two different entities, we consider it may be more appropriate to require ongoing annual signatures from the Dispatch Controller, not the Legal Owner.

Question 8: Do you believe the current length of the Prequalification window is appropriate and if allowing Prequalification submissions to take place throughout the year would be beneficial?

We consider that it would be beneficial to allow prequalification submissions to take place throughout the year.

Question 9: Do you have any feedback on the options presented in relation to the submission of planning consents and if there are any alternative options that we have not yet considered?

We support deferring the requirement for planning consent from prequalification to the Financial Completion Milestone.

Question 10: Do you have any feedback on the amendments to the Prequalification data items listed in Table 1?

We support the proposal to remove or delay the items listed in Table 1.

We would also support removing the requirement to provide historic generation data where an Existing Generating CMU is applying based on Connection Capacity and the SPDs have been proven.

Question 11: Do you believe that removing progress reports and the associated ITE assessments in all cases except those outlined, alleviates the regulatory and administrative burden, while still providing the necessary levels of assurance?

We support the proposal to remove progress reports and the associated ITE assessments.

Question 12: Do you have a view on which of the sub paragraphs of Rule 9.2.6(d)(i) – (ix) should only apply to Eligible Secondary Trading Entrants and which to the other categories of Acceptable Transferees?

The ADE has no comment.

Question 13: Is it appropriate to allow all parties who have prequalified for the CM for that year to become prequalified for secondary trading? Are there any unintended consequences?

We support allowing all parties who have prequalified for the CM for that year to become prequalified for secondary trading.

Question 14: What form should a register of Acceptable Transferees take? How should it be populated? And who should be responsible for maintaining it?

NGESO as the EMR Delivery Body should be responsible for maintaining the register and re-publishing updated versions on a very frequent (at least weekly) basis.

Question 15: Do you agree that it would be desirable to allow obligations to be traded between parties in amounts greater than or equal to 0.5MW?

We strongly support parties being able to trade smaller capacity than the current 2MW threshold. We consider that very small capacities will not be economically effective to trade and therefore, there will be a natural limit on the size traded. Therefore, we would question whether a minimum threshold needs to be set out in the Rules.

We do not agree that the Minimum Capacity Threshold should be retained for secondary trading. This creates a distortion as a result of de-rating rules. For example, a CMU with a connection capacity of 2MW and a de-rated capacity of 1.9MW would be able to participate in the Delivery Year with its own Agreement but not as a secondary trading entrant. We propose that either the Minimum Capacity Threshold should be removed or the maximum de-rating factor for that year should be applied for the purposes of secondary trading.

Question 16: Do you believe the current time period of five Working Days before the date of the trade by which applicants must submit a request to trade is appropriate or should this period be reduced? Do you have any suggestions on a revised length of this period?

We support shortening this time period to 2 working days.

Question 17: Do you believe that the current period of three months in which NGESO have to notify a Secondary Trading Entrant of the Prequalification decision is appropriate or do you feel this should be shortened? Do you have any suggestions on a revised length of this period?

We support shortening the notification period for prequalification decisions to 6 weeks or less.

Question 18: Do you agree with adding a provision for the time frame over which NGESO must respond to requests for a trade?

We agree with moving confirmation of the trade to when both parties have received notification. However, it is important that participants have access to an accurate Capacity Market Register. Moving to a real-time, updated database should be a priority for NGESO Delivery Body.

Question 19: Do you think it is appropriate to extend the defined trading window to the results day of the T-4 Auction for the relevant Delivery Year?

We agree with extending the trading window to just after the T-4 auction results day for the relevant Delivery Year.

Question 20: Does it continue to be appropriate for Transferors to be required to meet their SCM prior to engaging in trading?

Question 21: Does it continue to be appropriate for Transferees to be required to meet their SCM prior to engaging in trading?

In answer to questions 20 and 21, we consider an alternative may be to require new CMUs to meet their Financial Commitment Milestone before being allowed to trade.

Question 22: How should we address the risk of a trade being withdrawn where a Transferor is terminated after a trade has been registered?

The ADE has no comment.

Question 23: How should we address the transfer termination risk where a partial or full Capacity Agreement is traded for part of, or the entire duration of a Delivery Year?

We consider that the arrangements should be consistent between trades for part of the year and for a full year. Therefore, if the Rules remain that the obligation is not terminated when traded for an entire delivery year, this should also become the case for part of the year.

Question 24: Are there any amendments that could be made to the SPD framework following a secondary trade, specifically relating to partial agreement trades?

We agree that SPD requirements should be pro rata-ed where the trade is only partial – specifically, that only capacity up to the partially traded level needs to be demonstrated and only for the limited period within the delivery year that the trade comprises.

Question 25: Do you believe the options presented related to SPD data submission are suitable and are there any options we may not have considered in order to help mitigate the impact on capacity providers?

Submitting data more frequently and allowing CMU providers to self-verify the results will go some way towards resolving this issue.

However, we do not agree that it will fully resolve it. We propose that clear rules are established setting out an appropriate back-up data flow for CMU data to ESC that can be used in cases where the normal dataflow breaks down. This may require changes to the BSC as well as the Capacity Market Rules.

Question 26: Which aspects of a CMU configuration do you think should not be able to be amended following Prequalification?

We consider that the configuration of the CMU should be allowed to change as long as it delivers the same, or higher, de-rated capacity.

Question 27: Is there any other data that would be useful to add to the CMR and why?

We do not consider further data should be added to the register.

Question 28: How should the ALFCO formula be adjusted for Interconnectors when their output is affected by actions by NGESO?

The ADE has no comment.

Question 29: Should system to generator intertrips be included as a RBS in Schedule 4 to relieve providers of their obligations when affected by such an intertrip?

The ADE has no comment.

Question 30: How should we differentiate between firm and non-firm connection agreements at the Distribution level?

The ADE does not support differentiating between firm and non-firm connection agreements at Distribution.

Currently, distribution network zones using non-firm connections to constrain generation and storage are largely driven by solar investment in Cornwall and parts of Devon and South West Wales and wind farm investment in areas of the South East and across the Scottish DNOs.

At periods of high solar output, which usually occur during the middle of the day in Summer when demand is low, it is extremely unlikely that the electricity system will be facing a Capacity Market. In the South-West, periods of high solar output will most likely be the time when generation and storage is constrained.

At periods of high wind output, it is also very unlikely that the electricity system will be facing a Capacity Market event. Although this is more likely to coincide with periods of high demand during the Winter, strong wind output across the fleet will mean that there is unlikely to be a shortage of generation to meet such demand.

Currently and even more so in future, Capacity Market events are most likely to occur when renewable output drops to almost nothing – i.e. in cold, dark evenings with still weather[1]. This is why solar faces a 1.74% de-rating factor and onshore and offshore wind face 8-9% and 12-14% de-rating factors respectively.

Therefore, and if Ofgem does differentiate by connection type, we propose that NGESO conduct modelling to show clearly where there is coincidence between high periods of constraint and system stress events by each Distribution Network Operator and by each technology. This could provide a view of any risk arising from a non-firm connection for 1-year contracts.

However, it will not do so for 15-year contracts. Where new embedded generation is entering the Capacity Market, the level and pattern of constraints is likely to change significantly over the next 15 years as the background generation and demand mix changes. This will need to be taken into account when designing such a policy.

Finally, we would also note that Ofgem are currently reforming connection agreements at Distribution level with an explicit aim to provide connectees with greater choice and potentially financial firm, physically non-firm connections. Such changes would impact any framework for differing treatment of assets by Ofgem and BEIS within the Capacity Market.

Overall, the very different network conditions and drivers of constraint, the change that would be expected within a 1-year contract compared to 15-years and the current reforms towards greater choice all suggest that implementing any differentiation by connection type will need to be done on an almost CMU by CMU basis. We would propose that the risk to security of supply is quantified before a change of this magnitude is embarked upon to ensure cost-effectiveness and proportionality.

Question 31: How should Distribution-connected generators with non-firm connection agreements be de-rated to accurately account for their contribution in a stress event?

[1] Vivid Economics and Imperial College (2018)

Currently, de-rating factors are based on historical availability by technology type for most dispatchable assets and through the Equivalent Firm Capacity for storage and intermittent renewable generation.

In addition to our comments for Question 30, we would note that the Panel of Technical Experts has verified National Grid's methodology for the current de-rating factors and has not raised this as a concern. Given this, we consider that it should be the responsibility of the Panel of Technical Experts to review further changes to the de-rating methodology.

Question 32: Do NGESO's current financial incentives on demand forecasting accuracy, dispute resolution, DSR Prequalification, and customer and stakeholder satisfaction drive the intended behaviours by NGESO?

Without the Right First Time derogation, the NGESO remains relatively limited in its ability to support participants outside of the formal appeals process. Given the accelerated timetable for this year and the simultaneous undertaking of three pre-qualifications, we consider that restoring this should be a priority.

We consider that the financial incentives somewhat support the right behaviour by NGESO.

Question 33: Do the financial incentives listed above remain fit for purpose?

We agree that these incentives remain fit for purpose.

Question 34: What behaviours and outcomes should NGESO's financial incentives drive? What form should these incentives take?

The NGESO's incentives should drive it towards –

- Customer service that is quick to respond and supportive of smaller participants;
- Very frequently updated, if not live, information provision; such as for the CM register; and
- Systems able to scale to manage hundreds, if not thousands, of components

Question 35: Do you agree that a demand forecasting accuracy incentive remains appropriate?

The ADE agrees.

Question 36: Do you agree that the dispute resolution incentive should be based on a proportion of Prequalification or Reconsidered Decisions overturned by the Authority rather than on the absolute number?

The ADE agrees.

Question 37: Do you agree that the DSR Prequalification incentive should be replaced by an incentive intended to drive NGESO to aid smaller providers, new entrants, and innovators navigate the CM?

The ADE agrees.

Question 38: Do you agree that an incentive on NGESO's customer service and stakeholder engagement remains appropriate? What form should this incentive take?

The ADE agrees that an incentive regarding customer service and engagement remains appropriate.

Question 39: Do you agree that the incentives on NGESO for delivering the CM should be aligned with NGESO's incentive framework? Should the CM incentives be incorporated into NGESO's incentive framework in the longer term?

The ADE considers that alignment should be considered in the short to medium term; in particular, if the large investments in technology and platforms that NGESO is seeking are approved through RIIO-2. However, we also support the view that as far as possible, this should not preclude the possibility of opening up provision of the Delivery Body function to other bodies in the long-term.

Question 40: Does the separation of the EMR Delivery Body from NGESO continue to remain appropriate given the separation of NGESO from the rest of NGESO plc?

The ADE considers it remains appropriate.

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