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4th November 2022

SEM-22-054 Consultation Response

I am writing on behalf of the Demand Response Association of Ireland (DRAI), the trade association representing Demand Side Unit (DSU) providers in the all-island Single Electricity Market (SEM). By aggregating the flexibility from customers' otherwise passive electrical loads into substantial load portfolios, our members create predictable, reliable, and controllable assets, which provide a valuable source of Demand Side Flexibility (DSF) that can be actively used by system operators to meet the needs of the power system.

Today, the DRAI represents approximately 700 MW of demand and embedded generation response across hundreds of industrial and commercial customer sites throughout the island of Ireland. These sites are managed by our members who actively participate in the capacity, DS3, and energy markets.

DRAI members are committed to shaping the future of power system flexibility through advancing DSF on the island of Ireland. As Ireland strives to achieve its renewable generation targets for 2030 and beyond, our promise as an industry-led organisation is to champion the development of innovative DSF solutions that are designed to address the system-wide requirement for flexibility.

The DRAI expresses a single voice on policy and regulatory matters of common interest to its members, and we welcome the opportunity to provide feedback on the SEM-22-054 consultation on the EY Review of the Performance of the SEM Capacity Remuneration Mechanism.

On behalf of the DRAI, I hope that you find our response helpful and constructive.

Siobhán McHugh
DRAI CEO

BACKGROUND – THE CRM AND DEMAND RESPONSE

The Demand Response Association of Ireland (DRAI) supports the review of the performance of the SEM CRM and the intention of the SEM Committee to publish a plan of action on the next steps for the recommendations proposed. The DRAI has long advocated for a capacity market design which allows full participation of demand side resources, for the benefit of the whole power system.

The European Commission State Aid Approval for the Capacity Remuneration Mechanism[1], as well as the Electricity Regulation (2019/943) and Electricity Directive (2019/944) which form part of the Clean Energy Package, include clear obligations to fully integrate DSUs, ensuring non-discriminatory access to all electricity markets. To date these obligations have not been met and work is still required to address shortcomings in the current market design.

DRAI members' portfolios have delivered time and time again throughout the past year and have been heavily utilised to mitigate the widely publicised generation constraints that Ireland has experienced. Customers from industries as diverse as cement, pharmaceuticals, mining, manufacturing and hospitality have responded to provide capacity during system stress. However, the current limitations on electricity market incentives for demand response remain an obstacle to participation.

DRAI RESPONSE TO THE CONSULTATION

Below we outline the DRAI position on items highlighted in the EY Review of the CRM that are of particular relevance to DSUs and their operation in the market. In addition, we provide information on issues impacting the ability of DSUs to fully participate in the capacity market.

ENERGY PAYMENTS FOR DSUS

The SEMC recognised that the CRM design did not allow consistent treatment of units offering demand response (DSUs) in respect of their exposure to difference payments. While the SEMC determined that the interim solution for DSU energy payments (making them only during periods when difference charges are payable) implemented by SEM-19-029 was sufficient to comply with the requirements of the CRM State Aid approval, a significant market distortion between DSUs and generators remains, and this falls far short of the equitable treatment and full market access required under the Clean Energy Package.

We note that the EY Review recommends that Energy Payments for DSUs is implemented:

- Implement baseline methodology for assessing the contribution of DSUs in reducing energy demand.
- Pay DSUs for negative generation up to the RO strike price

This has been the subject of consultation under SEM-22-036[2] and the DRAI expects that this process will continue to progress under the current consultation and regulatory timelines set out by the RAs.

APPLICATION OF RELIABILITY OPTION DIFFERENCE CHARGES

Similarly, the SEMC recognise in the consultation paper that work is currently underway in relation to the application of non-performance difference charges to in-merit units. This risk poses a significant

[1] https://ec.europa.eu/competition/state_aid/cases/267880/267880_1948214_166_2.pdf
[2] DRAI response to SEM-22-036 available here

threat to DSUs and other units in the market, and a solution is urgently required. The DRAI expects that this work will continue as proposed under SEM-22-030 consultation process and urges the SEMC to implement a solution for this issue at the earliest opportunity. This unmanageable risk means that no matter how much effort aggregators put into being available and performing reliably, it doesn't significantly reduce their potential penalty exposure.

PERFORMANCE SECURITIES AND THE TERMINATION CHARGES

The current application of performance securities and termination charges is problematic for DSUs. The cumulative effect of performance securities across multiple auction years alongside the high rates applied gives a bias towards larger market players. The DRAI recommends that the applicability of Performance Securities to demand side capacity across successive auctions is reviewed by the SEM Committee.

The existing levels of Performance Security costs already entail a business decision which is intended to dissuade participants from continuing except where they have high level of confidence of success. Where this mechanism is not successful, and a participant fails to deliver, we would encourage the introduction of a process that addresses the greatest risk and likelihood of failure. This would suggest that the application of these costs should be allocated in a greater proportion, aligned to risk profile, to long term 10 year capacity and larger single site units, the failure of which would result in a greater capacity adequacy deficit.

ADMINISTRATIVE SCARCITY PRICING

We note also the recommendation to re-examine the operation of Administered Scarcity Pricing (ASP). This would require careful consideration, since these parameters are key assumptions under which fixed-price contracts are entered into under the CRM.

We call attention to the fact that any change to the invocation triggers or magnitude of ASP would also exacerbate the financial risks to participants resulting from the application of Difference Charges to available in-merit units.

It is therefore imperative that further modifications to the ASP mechanism are not made until the resolution of the issues described in the SEM-22-030 consultation, for all affected unit types, including Demand Side Units.

ADMINISTRATIVE PENALTIES FOR NON-DELIVERY OF PLANTS IN SPECIFIC LOCATIONS

It is important that the design of any such penalties gives due consideration to the nature of aggregated units and does not inadvertently impose restrictions on aggregation that would further erode aggregators' ability to combine sites and response capabilities to meet market obligations.

MONITORING OF PERFORMANCE DURING STRESS EVENTS

The review recommends "greater monitoring of technology performance in stress events to inform future de-rating factor setting". The DRAI would like to highlight that this cannot be done without consideration of the market conditions, incentives and barriers that exist for particular technology types.

We note that the SEMC has recently published a consultation on the "Proposed Methodology for determining auction capacity requirements and de-rating factors" (SEM-22-075). In the TSOs' paper, the derating methodology is proposed to be amended to use "DSU outage statistics … assessed on the basis of their own performance, rather than being assigned the system wide average outage rate."

This methodology is not suitable for DSUs given that the historical statistics used in modelling by the TSOs are for availability of DSUs while operating in a flawed market design, in the absence of energy payments and without the full integration of DSUs required by the EU State Aid approval for the CRM. At this point in time, and until the issues impacting DSUs are resolved, there is no relevant historical information for DSUs that can be used to assess performance.

The TSOs view that there are now “five years of outage statistics under the new arrangements” takes no account of these factors. The methodology cannot be viewed as a suitable means of assessment for DSUs when there is acknowledgement of the need to address missing signals and flawed market design as set out in SEM-22-036 on Energy Payments for DSUs.

Under the current market design, DSUs must meet their load following reliability obligation, aligned to the market signals provided by the Capacity Renumeration Mechanism (CRM). Demand side unit aggregators respond to the signals that are present in the market and work with the constituent client IDS within their portfolio to maximise availability at times of system stress.

A DSUs’ technical availability depends on their customers’ commercial availability. The TSOs proposed methodology in SEM-22-075 does not (and could not) represent an accurate view of future DSU capacity market participation, as it does not take account of the missing market signals which would incentivise DSUs to make capacity available above their load following obligation. Using historical data collected during a period where it is acknowledged that market signals for DSUs were flawed, is simply not appropriate.

Single Derating Factor for DSUs

Scale-based derating is a barrier to DSU market participation and the suggestion to set a derating factor for DSUs regardless of size is welcome and common sense.

Ability to Secondary Trade

The restricted nature of secondary trading means that aggregators seeking to move capacity obligations between DSUs must provide years of notice and post extra performance security, making the process inflexible and costly. Best practice would be to minimise the friction, so that aggregators can actively maintain their portfolios to ensure they deliver reliable performance even as individual DSUs are affected by changes in the capabilities of individual customers.

ADDITIONAL BARRIERS TO AGGREGATION

The DRAI would also like to highlight further barriers to aggregation that limit the ability of demand side resources to participate in capacity markets. These are in addition to those discussed above around energy payments, RO difference exposure, scale based de-rating and the lack of secondary trading.

Aggregators are limited in their ability to maintain availability and reliable performance by adding or replacing customers to match capabilities to obligations. The causes of this can be attributed to:

- *Fragmentation* - obligations are assessed on a per-DSU basis, rather than across the whole portfolio. This limits the aggregator’s ability to flexibly match available response from customers to real-time system needs. The DRAI has requested changes to the Capacity Market Code (CMC) to allow for this via modification proposals CMC_10_21 and CMC_07_22. The issue is further exacerbated by requirements to align individual sites within a unit based on location and response duration, lessening the ability of the aggregator to manage the obligation.

- *Grid Code and technical limitations* – sites above 10 MW cannot be aggregated in a DSU and must exist as a single-site unit, removing the aggregator's ability to use a portfolio of customers to deliver more reliable performance than a single customer. Units are also required to be above a minimum size of 4 MW, creating a barrier to participation in the market. The grid code requirement for a minimum 2 hour response duration is an artefact of the previous market design which did not apply de-rating, however this barrier remains and excludes viable response from market participation.

- *Barriers to entry* – as well as unit size and duration issues highlighted above, requirements around telemetry are over-specified and expensive. This cost is prohibitive and limits the ability of new parties to enter the market as aggregators. It will also limit the viability of working with large portfolios of smaller customers as the electrification of smaller-scale heating and transport demand proceeds in line with decarbonisation policy.

BIDDING CODE OF PRACTICE (BCOP) AND DSUS IN THE MERIT ORDER

The fundamental design of the current BCOP is based on the economic models associated with conventional generation market participants and is not fit for purpose for DSUs. Under the BCOP, aggregators cannot represent the true incurred costs of participating customer sites. This inflexibility means that customer sites are not fully compensated for the cost and disruption of dispatch.

Forcing aggregators to offer at artificially low prices also tends to lead to DSUs being dispatched more frequently, which in turn can lead to customers becoming less available. While the price at which DSUs offer into the energy market does not directly impact on the CRM, this secondary effect can harm performance during stress events, where continued dispatch without adequate compensation leads to customers being unable to participate.

Demand side unit costs are not straightforward to calculate in a similar way to conventional generation units. The commercial availability of participating customer sites is the key factor which determines a DSU's ability to maintain availability and meet market obligations. BCOP fails to adequately allow for the disruption caused to participating businesses that deliver demand response e.g. risk of damaging relations with their customers that are impacted by process disruption.

Essentially this means that aggregators cannot ensure that their customer's full cost of dispatch can be recovered, and thus it makes it incredibly difficult for aggregators to ensure high availability declarations for individual customers. From an economic perspective, where a customer bears a large opportunity cost, it is inefficient to dispatch them in preference to a generator whose costs would be lower.

SUMMARY OF DRAI RESPONSE TO THE CONSULTATION

The DRAI welcomes the review that has been carried out on the CRM. Our response has outlined a number of key issues in relation to DSUs, which need to be resolved in order to properly facilitate demand side participation in the market, among them;

- Delivering Energy Payments for DSUS, as highlighted in the EY Review, is critical in achieving equitable treatment for DSUs required under the Clean Energy Package and providing clear market signals.

- The risk posed by the application of non-performance difference charges to in-merit units must be resolved urgently.
- The TSOs' recent proposal under SEM-22-075 to use DSU-specific outage statistics to calculate de-rating factors is not appropriate while known market design flaws still need to be addressed.
- The current BCOP makes it difficult for DSU aggregators to reflect customers' full cost of dispatch, and needs to be reviewed.

CONCLUSION

The DRAI welcomes the publication of this consultation as an important step forward in addressing market deficiencies in the CRM and an opportunity to put forward our views in relation to the treatment of demand side units.

As well as being needed to meet immediate security of supply needs, flexibility from demand side units is essential to enable the further decarbonisation of the electricity system. This need for flexibility has been clearly set out in the EU-SysFlex[3] programme of work, and the recent ACER Decision[4] on the ENTSO-E European Resource Adequacy Assessment.

EirGrid and SONIs' own Shaping our Electricity Future work, and the technical studies around high RES-E system operation also call out demand response and flexibility as key elements of the future power system. Demand side units have been highlighted as key providers[5] of future system services and capacity adequacy. Efforts need to be made to ensure a capacity market design that positively impacts participation of these low carbon technology types in the electricity market, and properly incentivise service provision to the power system.

It is critically important to deliver equitable market rules for demand side participation in order to deliver essential services to the power system needed for capacity adequacy and to meet decarbonisation goals. The necessary changes outlined in this response, which are required to meet the requirements of the Electricity Market Directive, are long overdue and need to be progressed without delay.

[3] The outcomes of the EU-SysFlex Project – EU-SysFlex
[4] ACER decides not to approve ENTSO-E's first pan-European resource adequacy assessment due to shortcomings | www.acer.europa.eu
[5] Potential Solutions for Mitigating Technical Challenges Arising from High RES-E Penetration on the Island of Ireland