ESB Generation and Trading Response to SEMC Consultation Paper on Demand Side Units: A Revised Phase 1 Solution for Energy Payments and Other Issues

(SEM-24-046)

25/10/2024

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1. INTRODUCTION

ESB Generation and Trading (GT) welcomes the opportunity to respond to the *Demand Side Units: A Revised Phase 1 Solution for Energy Payments and Other Issues Consultation Paper (SEM-24-046)* (the Consultation). The Consultation sets out:

1. **Equitable treatment between all market participants** in terms of bidding, availability, metering, and balancing market responsibility.
2. **Clear rules in place for providing the demand response** in order to run an efficient and cost-effective power system that provides reliable power to end customers on the island or Ireland.

Considering the rising importance of both explicit and implicit demand response that was highlighted in the ACER Demand response barriers paper[1] and the current development of a demand response network code (consultation closing at the end of October 2024[2]) and last but not least Ireland's own National Energy Demand Strategy (NEDS)[3] **it is crucial to ensure all market participants adhere to same principles of operation giving all types of units in the market equal opportunities to provide their services.**

ESB GT will not be responding to all questions outlined in the consultation paper, our response will focus on areas where we believe a new approach is necessary to achieve the above-mentioned principles. We trust you will find our comments helpful and constructive.

2. EXECUTIVE SUMMARY

The treatment of DSUs under Trading and Settlement and Capacity Market rules has undergone multiple changes since I-SEM Go-live.

Unfortunately, there are still significant provisions allowed to DSUs that are not in line with treatment of other units, in particular Generator Units. **The most critical issue is the continued absence of operational metering**. Missing operational metering means units are renumerated based on the presumption of service provision and not the actual provision of service. **This removes a significant incentive to encourage desired outcomes in terms of performance.**

1 ACER MMR 2023: Barriers to demand response (europa.eu)
2 PC_2024_E_07 - Public consultation on the draft network code on demand response | www.acer.europa.eu
3 NEDS_Decision_Paper_and_Annex.pdf (divio-media.com)

The result is that DSUs are not fully balance responsible – balancing market settlement of the unit presumes the demand response was delivered in full at all times and unit gets renumerated accordingly. While DSUs currently do not receive Imbalance payments (CIMB) they are entitled to their fixed costs (shutdown costs) and also the uplift in cases where the Commercial Offer Data (COD) Price of the unit is higher than the Imbalance Price (PIMB).

Data provided by RAs and SOs demonstrates that DSUs have a poor level of performance when called upon.

This differential treatment conveys significant advantage relative to other units that are renumerated strictly based on their actual metering.

This situation can result in discrepancies between instructed (and renumerated) demand response and the actually delivered volume. ESB GT is aware TSOs are conducting performance analysis and contacting underperforming units requesting an explanation and remedial actions.

However, this ex-post analysis does not have any impact on market settlement values and underperforming units are still being renumerated as if they performed in line with expectations.

Where the DSUs do not provide the instructed volumes, other units will be called to compensate and/or system performance will be degraded.

As it stands, there are rewards for DSUs on the presumption that they will deliver but no penalties if they fail to deliver. **Market rules must be such that the correct behaviours and performance standards are incentivised.**

The second issue we wish to highlight is closely connected to the missing operational metering – the baselining and performance monitoring. The main capability of the demand response in the energy market is the ability to decrease demand of the site(s) unit that it is associated with. The inability to correctly and confidently assess if the response has been delivered in both real-time and ex-post can result in an additional vulnerability of the power system at times where demand response can play a crucial in ensuring the system stability.

ESB GT believe there should be further investigation of the data currently provided to TSOs as per Grid Code requirements (Best Correlated Profile, Energy profile, etc.) and its suitability for performance monitoring and baselining.

While missing operational metering is in our view the most pertinent issue, the bidding issues that have been highlighted within the consultation paper are an additional important consideration. This issue brings up a question whether there should be a standalone license for Demand Side Units/Demand

Response Units in general that would formalize the bidding requirements for units providing demand response.

From the presented arguments in the Consultation, it seems the bidding rules do not capture the nature of units providing demand response in a way that would allow the same level of oversight by Market Monitoring Unit as is currently in place for other types of units participating in the market. Compliance with bidding rules is essential to a well-functioning market with equal standards equally applying to all parties. Rather than altering the current Generator licence it may be appropriate to develop a set of guidelines that capture the nature of all demand response units as has been suggested in the Consultation.

In relation to the topic of 'long-run' DSUs and the appropriateness of them being treated the same way as 'intermittent' DSUs, we agree that this is a key area for consideration by the RAs. In cases where the unit is providing a demand response solely via on-side generation that is also used for other purposes within the site (e.g. Combined Heat and Power (CHP) generators) or is already supplying part of the electricity needs on the site it is perhaps appropriate that such a unit be categorised as a Generator Unit, Aggregated Generator Unit or Autoproducer Unit.

The TSOs are currently developing arrangements for Dispatchable Demand/Consumption under the Future Power Markets Workstream which will provide market access for units with ability to increase demand on the site and therefore prevent curtailment of intermittent generation at times of high wind and low demand. ESB GT believe there is a merit in expanding this task to create new arrangements for all demand response units.

Lastly, the issues highlighted in this paper in conjunction with multiple workstreams currently assessing the market participation and treatment of Demand Response on both national and EU level suggest that there needs to be an integrated and comprehensive review of overall arrangements for Demand Response participation.

Whilst this Consultation mostly focuses on Phase 1 of the Energy Payments Solution, ESB GT believes the Phase 2 (as enduring solution) should commence its development in parallel and provide a robust set of regulatory rules that will allow for the future Demand Response participation and create a level playing field for all participants in the market.

3. RESPONSES TO CONSULTATION QUESTIONS

As mentioned in the Introduction chapter ESB GT currently does not operate or own any DSU therefore we wish to respond only to questions related to wider market issues – e.g. metering, baselining, classification of the units etc. To ensure the ease of orientation in our response questions we are not responding to are in grey, while the questions with response are in blue. The numbering is retained from the consultation document.

Q1: Do you agree with the description and analysis of the models for compensating demand response and, in particular, for energy payments to DSUs? Please explain your view.

Q2: Do you agree with the description and analysis of the appropriate treatment of 'long-run' DSUs? Please explain your view.

Q3: Do you agree that incorporation of a supplier compensation payment between DSUs and suppliers would be an appropriate mechanism for addressing the 'missing money' problem for DSUs? Please explain your view.

Q4: For the revised Phase 1 solution, if it isn't possible to identify the affected suppliers, do you agree that it would be appropriate for the supplier compensation payment to be paid into the Imperfections Charge fund? Please explain your view. Do you consider that this will allow DSUs to compete on an equal footing, without any undue disadvantage or undue advantage, compared to generators? Please explain your view.

Q5: How do you think the Supplier Compensation Price (PCOMP) should be calculated? What costs should be taken into account and what costs should be ignored? Please explain your view.

Q6: Do you agree that a supplier compensation payment would have the correct incentive effect on long-run DSUs, as well as other DSUs, and would impose reasonable costs on end consumers? Please explain your view.

Q7: Do you have any views on whether supplier corrections for non-consumed energy could be determined by voluntary agreement between the supplier and the DSU, or by ex-post analysis of demand reduction dispatch decisions? Please explain your views.

Q8: Do you agree that it would be possible to categorise DSUs into long-run and intermittent DSUs by some other criterion, such as running hours, such that it would be possible to determine whether or not compensation for 'missing money' would be appropriate? If not, please explain why. How could such a test be implemented, in practice, and eligibility criterion enforced? Should such a test be used instead of, or together with, supplier compensation payments? Please explain your view.

ESB GT believe that the workstream underway within the Future Power Markets programme in relation to Dispatchable Demand/Consumption units should be expanded to assess the appropriate categorisation of these type of units. This is in particular appropriate when onsite dispatchable generation is the means by which the demand response is provided.

Q9: Do you agree with the description and analysis of the appropriate treatment of Capacity Payments and Capacity Charges? Do you think that Capacity Charges should be levied on non-consumed energy, e.g. by an adjustment to the supplier compensation price? Please explain your view.

Q10: Do you consider that some form of baselining is needed? Would appropriate supplier compensation payment arrangements affect this? If baselining is needed, do you have any views on how the baselining methodology should work? What should be taken into account in determining the baseline profile? Please explain your view.

It’s crucial the Demand Side Units are performing according to the same standards as other market participants. We understand these units are does run differently than other generating units however there are already performance monitoring rules in place within the Grid Code (GC). Part OC.10.4.5.2 of Eirgrid Grid Code sets up the rules for DSU compliance with Dispatch instructions. Considering these rules are already in place ESB GT believes they can be utilised immediately to provide an initial view on the unit’s performance. In cases where unit does not perform according to these rules TSO should be able to overwrite currently used logic (QD=QM) with a value of demand that unit did provide. This approach would create a link between performance monitoring on the Grid Code side and Market Settlement and could be implemented as an ex-post process with new values being submitted for Initial (D+5) or first scheduled resettlement run (usually M+4). The timing of the submission of revised values should complement the timeline of the current performance check process that TSOs are carrying for DSUs. While we would consider this solution being only an interim one, we believe it could be implemented in relatively short time and could be used until the enduring solution with a full operational metering is delivered. ESB GT believes there is a need for an enduring solution to be delivered as soon as possible however the currently used logic that does not fully incentivise units to deliver the instructed demand response should not be in place any longer, therefore the interim solution should be adopted in a short term.

In the more general view of baselining, we believe there should be a comprehensive review of other provisions currently in place under the Grid Code – e.g. Demand Side Unit Best Correlated Profile and Demand Side Unit Energy Profile. We believe units should only be renumerated in cases where they had to respond to the dispatch instruction by altering the overall demand impact of the site on the transmission/distribution system. It's imperative for TSOs to be aware of the typical/estimated demand profile of the site before issuing the dispatch instruction as the site may be lowering their demand in the period regardless of the instruction from TSOs being issued or not. These Grid Code provisions were not discussed in the consultation paper however ESB GT believe they should be explored in conjunction with seasonal, etc. profiles to ensure TSOs have the full picture when making dispatch decisions.

Q11: How important is it to use sub-metering? Please explain your view.

Q12: Would it be appropriate to use SCADA data for the purpose of setting DSU metered quantity? How could this arrangement work in practice? Please explain your view.

Joint response for Q11 and Q12

As mentioned in our response to Q10 ESB GT believe there is an urgent need to create a link between DSU performance and its market settlement. TSOs are already receiving the SCADA data from DSU operators therefore naturally this data should be used in a short term as a replacement of operational metering. Depending on a result of the Demand Response Networks Code consultation the move towards sub-metering may be required in the future however that should not stall/delay the process of creating more equitable landscape for performance monitoring and settlement renumeration within I-SEM.

While we understand the current metering arrangements were put in place to allow DSUs access to the market and encourage investment into the new technology we believe DSUs have now progressed to more mature technology and should therefore follow the same arrangements as other units on the market. With ever increasing share of intermittent generation on the system DSUs will likely provide increasing amount of services in both energy and non-energy space. Operational metering will provide an importing data source for overall assessment of the impact DSUs have on the system.

Q13: Do you consider that on-site generation could be accommodated in the SEM through the arrangements for Aggregated Generator Units? Are there reasons why it makes more sense to use Demand Side Units? Please explain your view.

There is currently no restriction on the maximum length of demand response unit can provide. This creates a situation where units able to provide 0.5h of demand response and nearly continuous demand response are treated under the same set of rules. The utilisation of other, more appropriate, arrangements already existing under TSC should be encouraged as a viable option for long-run DSUs using the on-site generation. Aggregated Generator Unit (AGU) could be utilized by units having multiple De Minimis generators on the site which are used solely for purpose of lowering the demand needs of the site on the overall system. For units that use their on-site generation and can potentially have an excess that could be provided to the system there may be an opportunity to create similar arrangements that are currently in place for Autoproducer units. Both of these options would allow TSOs to utilize units' full potential more efficiently and it will also allow for more cost reflective bidding and bidding enforcement as these types of DSUs would have more similarities with conventional generators (fuel costs, etc.) than with 'short run' DSUs. DSU owners/operators would benefit from these arrangements by being able to retain the full benefit of market participation without complexities of sharing it between themselves and the supplier.

Additionally, some demand intensive projects (e.g. datacentres) are required to have an onsite generation as part of their Planning Permission in line with Government Policy. These market participants should be encouraged to participate as generator type units (either standalone, aggregated or autoproducer) especially if the onsite generation is running perpetually suppling baseload needs on the site. Including these units under generation portfolio would provide more accurate picture of the overall generation mix within I-SEM.

Other considerations for inclusion of on-site generation DSUs are discussed within our response to Q15 in regard to treatment of negative response.

Q14: Are there any other issues relating to the treatment of DSUs in the SEM, which the SEM Committee should consider when implementing a revised Phase 1 solution? If so, please explain these issues.

The consultation paper in part 5 states that the changes in treatment of DSU does not need to consist of a single package but can involve a series of changes that can be implemented individually. ESB GT understands this approach is likely due to the volume of different issue and concepts discussed within the paper. With the increasing amount of DSUs being registered in the market we would like to ask RAs to consider implementing the Phase 1 changes that can use the existing environment and available data (performance monitoring, metering, and bidding) as quickly as possible. While it's appropriate that DSUs have access to full energy payments to not only bring them on the same level as other market participants but also comply with our Capacity Market State Aid approval granted by European Commission in 2017, changes that do require system releases should not create a roadblock to implementing other improvements in DSU treatment in the interest of equity amongst market participants and value for money for consumers.

When it comes to Enduring solution (Phase 2) we believe there is a need to review the full regulatory approach to Demand Response participation in the market and assess whether the current arrangements are still fit for purpose at the time where the importance of Demand Response is increasing, and the need of equal treatment is discussed on EU and national level. Within the NEDS decision paper (page 18) it was stated TSOs are to publish Demand Side White Paper that should outline the high-level demand side plan including changes needed for meeting flexibility targets. At the same time TSOs are working on arrangements for Dispatchable Consumption (Demand Response units providing increase of demand – opposite of current DSUs) as part of Strategic Markets Programme (SMP). The wide range of issues discussed in this paper in conjunction with above mentioned initiatives may warrant the development of Demand Response specific licence to ensure units providing any type of demand response have a robust and specific framework that provides certainty to the unit owners/investors and also to TSOs and RAs in their respective roles of system optimization and rules enforcement.

In all cases we believe there is a need for coordinated approach ensuring both the interim (Phase 1) and enduring (Phase 2) solutions will provide an optimal result for market as a whole and ultimately for the end consumer.

Phase 1 may focus on solutions available within the current system and regulatory landscape (e.g. using SCADA metering, utilizing currently available forecasts for baselining, providing bidding guidance, etc.), however Phase 2 should establish arrangements that will accommodate the expected future uptake in various services provided by Demand Response. In the 2011 SEMC Demand Side Vision for 2020[4] (SEM/11/022) RAs identified multiple areas that could benefit from greater demand side participation – e.g. decrease of wind curtailment in the off-peak periods and help to mitigate transmission and distribution network constraints. While some of the identified drivers of higher (peak)

[4] SEM-11-022 Demand Side Vision for 2020.pdf (semcommittee.com)

demand are still in development (district heating, price-responsive charging of electric vehicles) we can clearly observe the increasing level of Demand Side Units in the I-SEM. Phase 2 arrangements should recognize Demand Response units as a mature technology type that is able to fully compete in the market and therefore should have the same level of rigor in its participation as other market participants.

ESB GT is cognisant of the focus of this consultation paper however we believe it's necessary to broaden the discussion regarding the enduring arrangements for Demand Response participation and the need for creating level playing field between all market participants. The current ambiguity does not provide for equal treatment or efficient market outcomes which ultimately negatively impacts the end consumer.

Q15: What are you views regarding negative demand response? Do you consider the supplier compensation payment arrangement will work for negative demand response? Do you think there is any potential for perverse outcomes and undue discrimination between customers? Please explain your view.

ESB GT is aware of the current workstream under Strategic Markets Programme (SMP) that currently explores the options for Dispatchable Demand/Consumption (increase of demand upon receiving instruction from TSO). These arrangements should allow a use of units that can increase demand on the system by increase running of the internal on-site process, e.g. electro boilers and electrolysers for hydrogen production. These units will play an important role at times where there is an excess of intermittent renewable generation on the system and therefore decrease the need to dispatch down these units.

As presented at the Future Power Market Workshop in October 2024 the current view is Dispatchable Consumption Units (DCUs) will participate in the market as a new technology type but with same obligations as other market participants without any special provisions that are currently allowed to DSUs. As mentioned above in our response for Q14 we believe this maybe an appropriate time to create more robust regulatory frameworks for all types of Demand Response including a specific licence.

When exploring options for treatment of these units there may be a space for units that can do both positive and negative demand, essentially working on a reverse principle of battery units. This option could also include some units that are discussed as 'long-run' DSUs in this consultation paper which the SOs confirmed at the workshop was their current thinking. As the workstream in currently in an explorative phase and no decision on the future of negative demand units has been made, we believe there may be a merit to explore the option of units that can provide both negative and positive demand response.

Q16: How should shutdown costs for IDSs be accurately reflected in the COD for DSUs? Please explain your view.

Q17: How should decremental bid prices to reduce demand reduction be calculated? Under what circumstances do you consider that decremental prices could be negative? Please explain your view.

Joint response for Q16 and Q17

Any bid submissions need to ensure they are in line with Bidding Code of Practise. If necessary, the guidance suggested in the consultation should be issued to ensure there is a clear baseline that can be used to assess DSUs bidding behaviour is appropriate. The goal of such guidance should be providing clarity to DSU operators and also aligning the bidding behaviour and the enforcement of thereof with other units in the balancing market.

Additionally, it's crucial DSUs are complying with financial regulations rules – e.g. REMIT. While the consultation paper does not cover this topic, we believe it is closely related to BCOP compliance.

Q18: Do you agree that the Grid Code requires DSUs to declare an availability of 4 MW or above on a regular basis? If not, please explain why.

Eirgrid Grid Code part SDC1.4.3.4 in conjunction with part SDC1.4.3.5 does not state any availability value that DSU has to declare except of that fact that must be achievable and within its technical parameters. Consequently, Grid Code definition of the Demand Side Unit states that the Individual Demand Site or Aggregated Demand Site has to have a Demand Side Unit MW Capacity of at least 4 MW. We believe this does not create a requirement to declare at least 4 MW of availability at all times. We do however believe that the DSU should be declaring accurately its availability at all times.

Q19: Do you agree that the Grid Code requires DSUs to round down their declared availability to the nearest MW? If not, please explain why