ETI Response to Demand Side Units: A Revised Phase 1 Solution for Energy Payments and Other Issues - Consultation SEM-24-046

ETI operates in the Demand Side Response sector of the electricity industry and perform a significant role in supporting the operation of the I-SEM balancing market and facilitating the continuous introduction of renewables.

The following comments are in relation to the published SEMC consultation and clause reference numbers are used where possible.

Introduction

ETI have significant concerns regarding the issuing of this consultation and its interaction with the Imperfections Charge consultation. This paper proposes to handle payment to Demand Side Units (DSU) <u>within the imperfections charge</u> however the recent consultation on the imperfections charge proposes to <u>remove the energy payment to DSUs from its forecast</u>. This suggests that there shall be further delay in providing payments to DSUs for the energy provided.
Payments for the Energy provided by Units operating in the Demand Response sector should be provided on a similar vain to other units operating under the Trading and Settlement Code (T&SC). This was to be implemented at the later part of 2023, was a recommendation from Europe, and the SEMC had initiated a workstream to deliver it. The delay has been somewhat frustrating and the indications within this paper, and those of the Imperfections Charge consultation paper, are altogether worrying.

The consultation paper itself has been difficult to follow and is severely lacking a plain English approach. We would hope that this is not a deliberate approach to confuse and mislead the reader. There are also some terms that are outside the usual industry understanding and that may be a reflection of the basic lack of understanding of how DSUs and Demand Response is provided from such a variety of IDs technologies.

The paper appears to have a narrow focus on Suppliers, Individual Demand Sites (IDS) and payment to/from DSUs. It does not encompass the costs of generation should DSUs not exist. This would result in more expensive generation being utilised to balance the System. <u>Existence of DSUs should be viewed as the avoidance of this extra cost.</u>

The paper concentrates too much on Suppliers and Customers and somewhat under values / undermines the service provision provided by DSUs in balancing the System

Comments on the paper's assumptions

The paper considers how to facilitate DSUs "to compete on an equal footing with other technologies", but the options put forward are not applied to other technologies. ETI would ask if the SEMC believes this to be equal treatment or a discriminating action.

The SEMC initiated action to look at paying DSUs for their Energy actions way back in 2022. DSUs have been providing their balancing services since ISEM began back in 2018. It could be said that the customer has benefitted from these services **FOR FREE** since DSU have not been paid for their energy. ETI would ask SEMO to identify the monetary amount that has not been paid to both 'Long-Runs' and 'intermittent' DSUs since then. If the SEMC believes that energy payments shall cost over €50 million per year going forward then we can assume the customers have already benefitted to the tune of €300 million, over the six years.

The volume of DSU (non long-run) would normally appear in the balancing market, which the Suppliers would not trade in advance. The paper overly concentrates on the Supplier benefiting from not buying this specific volume, but it is more likely that is not the case. There could however be a reduction in the Imperfections charge with more balancing actions by conventional generation **not** being utilised.

ETI agrees that the enduring solution (Phase 2) is difficult to implement, and costs associated with such are likely to force some DSU provision out of the market. Note that such market signals must be timed so that future Capacity obligations are not placed at risk.

The original consultation was not intended to burden the consumer with costs for actions that already existed. The drive was to pay DSUs for additional responses in balancing the System in replacement of additional Conventional Generation. Long Run DSUs were not considered as such balancing response and ETI agree that such 'Long-Runs' should be considered separate to the 'Intermittent DSUs'.

It is not accepted that Suppliers require to be compensated as part of the 'potential alternative Phase 2 solution'. The volume of 'intermittent DSUs' is small in the balancing market. The Balancing Market price is likely to be high if DSUs are required. The suppliers may have pre traded their overall volume in the Ex-Ante at a price below the Balancing Market. The requirement for DSU utilisation means the System requires additional 'generation' to balance and thus Suppliers have not purchased sufficiently. The suggestion is that demand reduction would reduce revenue from the customer to the supplier which is of course correct. The supplier should be paying for the balancing actions, since their trades haven't resulted in the System being balanced. Whilst individual supplier trades may not be the issue, then all the suppliers should cover this cost via the Imperfections Charge.

The suggestion that DSUs should provide a 'Compensation' to the Imperfections Charge fund means that the Offer price would need to cover this AND the cost of provision. This ultimately results in a higher Balancing Market price and potential overall increase in the cost to the consumer.

It should be noted that the paper makes the assumption that the 'savings to the customer' is readily identifiable. This reflects the major lack of information and understanding of how DSU demand reduction is currently calculated. As identified previously by the SEMC, it is difficult and expensive to implement systems that show the actual reductions on specific IDSs. These systems do not currently exist for the majority of IDSs. Because of this the proposed Phase 1 suggestion that the customer shares the saving in supplier charges with the DSU is unlikely to be workable.

ETI challenges the underlying thrust that availability declarations made by DSUs are not in line with the current Grid Codes. Declarations made via EDIL reflect the ability at that time of DSU response. Such declarations are not reflective of Capacity Market obligations nor of the registered capability of the unit. Any reference to such values again reflects the lack of understanding regarding the makeup of DSU technology and capabilities.

It has been discussed with the TSOs many times that the EDIL software is no longer suitable for today's markets and System operations, however the TSOs remain reluctant to address their issues. DSUs may not have the abilities of others in providing specific MWs and therefore need to round up to reflect that they can provide more than a certain whole number. ETI strongly suggests that a minimum value of 4MW declared availability is not considered as that does not reflect the fact that certain IDS shutdown at certain times. The 4MW in Grid Code is for registration and not operational declarations.

All costs for all units participating in the energy markets are reflective of the use of Central Dispatch and not Self Dispatch. As such all costs must reflect the best-case scenario of full dispatch by the TSOs as part of balancing the System, and Offers into the markets reflect that. It would be a challenge to have Price Quantity 'Shutdown' costs, and it would also need a change to the T&SC as well as the SEMO settlement systems.

Responses to posed queries

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.

The markets deal with Explicit response by the registered units, within the T&SC and we shall not comment on Implicit response mentioned in the paper. ETI acknowledges that the Models are NOT proposals for the SEM, but are for discussion in developing the Phase 1 approach.

Explicit response is provided by DSUs in their ability to aggregate a number of IDSs, each of which have their own unique abilities and parameters. These abilities result in DSUs availability being varied throughout the day, week, month, year.

Model 1 – No DSU payments. It is accepted that the customer would be purchasing less from a supplier. There is a saving to the Suppliers as their total metering would not be as high. There is a cost to providing the reduction, borne by the customer/DSU. <u>This model is not acceptable</u> as it does not cover the costs of providing the service.

Model 2 – DSU energy payments. This requires identification of specific metering of the reduction at each customer and DSU. This has already been identified as very difficult and costly to implement. It burdens the customer with supplier charges that it hasn't incurred and ignores any additional costs through loss of production and additional working to recover production. The DSU cost of provision is covered. <u>This model is not acceptable</u> as it burdens the customer and is difficult to implement.

Model 3 – DSU energy payment with supplier compensation. This requires identification of specific metering of the reduction at each customer and DSU. This has already been identified as very difficult and costly to implement. This is required so that it can be attributed to each specific Supplier, in order for them to purchase the volume at wholesale price. The requirement for the DSU to pay 'compensation' directly to the supplier is not accepted as a justifiable need. It is understood that the compensation may be a surrogate value for the loss of revenue from the customer. However, it is not an amount that the DSU can afford since it is not included in the Offer price to the market (€400/MWh).

Phase 1 revised. Customer purchases grid demand from supplier and supplier purchases its total demand from Wholesale market. DSU gets paid for its energy provision. This is funded by the Imperfections Charge fund, the same way any generation would be paid for balancing the system. ETI agrees to this approach. We do have an issue regarding any 'compensation' that may be paid back to the imperfections charge fund by the DSU. The DSU can not afford this as the Offer price only covers the cost of service provision. Any savings to the customer IDS would be individual and varied, and likely to be less than any 'Supplier Charge'.

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

ETI agrees with the analysis on 'Long-Run' DSUs, insofar as they do not provide explicit demand reduction as times when the TSOs see the System as 'tight' and requiring additional expensive balancing actions. Long-Runs do however provide reduction of the overall system demand, but at a time that suits them. This provision of 'energy' should not be disincentivised, as Demand has a significant role today and in the future in managing the balance of the System. Long-runs are mostly CHPs and can be viewed as a more efficient and cleaner provider of energy. The analysis pushes to make a distinction between the formats of 'Long-runs' and 'intermittent' DSUs. ETI accepts this approach, insofar as they operate in a different mode and the commercial Offers made to the market are significantly different.

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.

ETI believes that there should be equal treatment of generators within the market and that has been identified within European guidance with regards energy payments to DSUs. There are different forms of technology providing dispatchable response although not all are paid for their service under the current rules. The ability to identify specific DSU/IDS/Supplier demand reduction is difficult at this moment and thus compensation directly from DSU to Supplier is currently not possible. This also does not reflect the advantage to other suppliers due to the balancing price being kept down through the DSU dispatch, instead of other more expensive generation being used.

The calculation of the 'compensation' payment is also an area of concern, as the paper hasn't defined the full methodology of deriving it. This payment appears to be an effort to reduce the cost to the suppliers and move the assumed benefit from the customer via the DSU back to the supplier. The ability to balance the System shall benefit all participants and thus require payment for the desired outcome.

There may be an acceptable approach of having Long-Runs provide compensation, should they receive energy payments, but it would not be acceptable for Intermittent DSUs

ETI does not approve this approach of DSUs paying directly to Suppliers.

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.

The Phase 1 approach acknowledges the difficulty in identifying specific suppliers/customers. ETI would suggest that this difficulty shall also appear in the Phase 2 approach. The requirement for additional metering and settlement may drive certain IDSs to become unworkable and thus significantly reduce the provision of DSUs MW volume in the future.

Having said that the revised Phase 1 solution of utilising the Imperfection Charge fund would be acceptable to ETI. We would view that fund as spreading the benefit and cost across all suppliers, as they all benefit from the lower balancing market price affected by DSU participation, rather than the next more expensive for of generation.

ETI would look at this approach as being a useful part of the Phase 2 solution.

We do however have reservations regarding the payment of 'compensation' from the DSUs into the Imperfections Charge fund. Intermittent DSUs shall not have the financial ability to cover production costs <u>and</u> the compensation payment without increasing its Offer price to the market. The alternative would be to obtain a value from the IDS, which would require adjustment of contractual terms if possible. ETI would suggest that this would likely drive IDSs away and place an unwanted risk to the ability of DSUs to fulfil their Capacity Obligation.

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.

ETI have concerns over the application of a compensation payment to Intermittent DSUs as well as Long-Runs. This is to do with the ability to financially cover the amount.

There should be a separate approach, on the application of 'compensation' payments, for 'Long-Runs' and 'Intermittent' DSUs.

It is understood that 'Long-Runs' have lower running costs and offer such into the market. There is an inherent benefit to the IDS associated with such units. Since they often offer prices at zero or negative, then it can be suggested that energy prices at the Balancing Market value are not required. ETI suggests that the 'compensation' payment for 'Long-Runs' be made equal to any energy payments calculated. Currently the associated TSSU provides a similar function, insofar as it removes the payments to the DSU.

Whilst we do not believe that 'compensation' payments are appropriate for 'Intermittent' DSUs, any such calculations should reflect the <u>energy element</u> of the supplier tariff to the customer less any additional benefits obtained by the supplier in the wholesale market due to the actions of the DSU over the next more expensive dispatchable generator.

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.

Further to the comments made above in Q5, ETI believes that a correct calculation of the 'compensation' payment for 'Long-Runs' would have the result of allowing such units to continue to participate in the markets without significant negative impact. The use of the word "incentive" doesn't really cover this aspect, but we understand that lack of "Penalties" doesn't sound as useful.

Similarly, 'Intermittent' DSUs want to obtain energy payments, similar to other dispatchable generators so that they can efficiently cover the costs of provision of the balancing service. They best way to ensure the continued operational capability of the existing portfolios is <u>not to implement</u> any additional costs or complications between IDS and DSU. The 'penalty' of paying money to the Imperfections Charge fund or a supplier would not incentivise 'Intermittent' DSUs.

The paper has identified that the majority of potential additional costs would be due to paying 'Long-Runs'. The monetary amount for covering 'intermittent' DSUs is small in the overall Imperfections and therefore the correct 'Incentive' is to pay such DSUs for energy and not implement 'compensation' payments against them.

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.

The T&SC ensures that sufficient settlement funds exist to cover the costs of required generation. Voluntary agreements outside the T&SC could be seen as outside the scope of this paper.

ETI believes that the market settlement systems should be used through the use of ex-post analysis of demand reduction dispatch decisions. This would provide a more transparent approach and which would be under the governance of the RAs.

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.

ETI accepts that DSUs could be categorised into 'Long-Runs' and 'Intermittent' insofar as they operate in a different mode and the commercial Offers made to the market are significantly different. Whilst it is best to ask how they want to be categorised, the parameters to be used would be their Technical Offer Data (TOD) and their Commercial Offer Data (COD). 'Long-Runs' would normally be bidding in negative monetary values in order to stay dispatched and their running hours duration would be significantly greater than those of 'intermittent' units.

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.

ETI believes that the current Capacity Market is designed to be a financial hedge against Scarcity events in the Energy Market. Along with that the Capacity awarded amount allows for the provision of participants to cover overheads associated with the provision of capability. This provision of capability, and its associated costs, does not reduce through the actual use (dispatch) of such services. We do not see a suitable suggestion as to the justification of taking away capacity payments to participants, since they have invested in the provision of services. Under the current rules participants set out budgets and cash flows based on the cleared volume and price in an auction and it would be difficult to adjust such due to a centrally dispatched instruction by the TSOs.

We understand that any reduction in consumption from the grid by a customer shall result in a variety of supplier charges not being paid. These include Climate Change Levy as well as TUoS/DUoS payments and other elements. It is the general nature of suppliers to witness growth in demand as well as shrinkage in demand, and the Supplier can reposition their charges/tariffs to compensate.

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.

The paper discusses baselining as if the response provided by DSUs to a dispatch can not be trusted and this is an approach that ETI can not accept. The ability for each IDS to provide reduction is tested and baselined by the TSOs under Grid Code.

The nature of IDSs is that they are difficult to observe a repetitive consumption, due to the nature of production etc. The Capacity De-Rating factor that is calculated by the TSO already encapsulates the response nature of the DSUs as can be witnessed by the decrease in the value over the years. This may a reflection of the experience that the TSO have developed and the data they have analysed.

There is no requirement for further effort in performing baselining.

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

Sub-metering could provide a more accurate measure of the demand reduction provided by DSUs. However, the costs and benefits of implementing such a system need to be carefully considered.

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.

DSU operators are currently required to provide the TSOs with SCADA values that the DSU operator collects from all of its IDSs. Whilst these are not metering to the level required by Grid Code, they are an indication of the level of demand response based on the time of dispatch.

SCADA systems are already connected to the market operator's platform via secure, real-time data transmission protocols. This system leverages existing technology while maintaining flexibility and scalability for future market developments.

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.

The reduction of demand by an IDS can be provided without the use of 'Internal Combustion Engines' (ICE) and is normally provided through turning equipment off. AGUs deal with generators and thus they aren't appropriate for all DSU scenarios.

Currently AGUs require an equivalent value of maximum Export Capacity (MEC) which brings along additional costs, technical requirements and regulatory paperwork. IDSs with ICE engines don't require MECs, which could take years to obtain.

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 provision of Demand Response is a central thread to all the strategies published in NI and Roi. There is an onus on the RAs to ensure that such provision is supported in such a way that it can commercially survive and be treated in a manner similar, if not equal to, dispatchable conventional generation. Whilst the paper puts forward the essential requirement to pay DSUs for the energy balancing service it is placing many 'incentives' (penalties) that ultimately undermine any support that the RAs may want to express going forward.

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.

The idea of 'negative' demand response is something that has been discussed as part of Ancillary Services products. That however has been limited to frequency transient response to high frequency. <u>The TSOs do not view that as a dispatchable service</u> and have ruled out such being included in the Capacity Market. If there is a requirement for the TSOs to increase demand (consumption) then that capability would require similar investment to that of demand reduction. Such investment needs financial recovery via the Capacity market and ultimately the cost of responding to a dispatch would also require energy payment. Each IDS that increased it consumption would incur increased charges from it supplier.

If negative demand is not a dispatchable service then it shall not obtain Capacity Payments and thus the service is unlikely to be provided in the manner outlined in the paper.

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

DSUs currently comply with the BCOP and the proposals in the paper are not in line with BCOP. The suggestion that Shutdown costs should reflect the actual reduction is unworkable.

All costs for all units participating in the energy markets are reflective of the use of Central Dispatch and not Self Dispatch. As such all costs must reflect the best-case scenario of <u>full dispatch</u> by the TSOs as part of balancing the System, and Offers into the markets reflect that. It would be a challenge to have Price Quantity 'Shutdown' costs, and it would also need a change to the T&SC as well as the SEMO settlement systems

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.

This question may be answered differently by 'Long-Runs' and 'Intermittent' DSUs, and the market encourages lower Offer prices. The Market Monitoring Unit (MMU) also regulates/approves the Complex Offers provided by DSUs and other participants.

The decremental bid price for reducing demand reduction should be calculated by considering a range of factors, including the operational costs of increasing demand, opportunity costs associated with foregoing further demand reductions, market price signals, restart costs, potential revenue gains, and system conditions.

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.

The 4MW in Grid Code is for registration and not operational declarations. The assumption in the paper that there is a requirement to declare an availability of 4MW or more **is in error**.

The value of 4MW has been queried previously during discussion of Grid Code modifications to reduce this 4MW value to 1MW. There was no reason provided by the TSOs regarding the value. The TSOs did however identify that they were unable to handle multiple small units. Should the RAs or TSOs introduce a requirement to declare at or above the minimum grid code value then industry would again raise a modification to address that value.

To do otherwise means that the TSOs are missing out of valuable demand reduction.

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.

It has been discussed with the TSOs many times that the EDIL software is no longer suitable for today's markets and System operations, however the TSOs remain reluctant to address their issues.

The paper correctly identifies the requirement for the TSOs to allow bids at 0.1MW granularity, but that requires a system to handle availability declarations.

Should a DSU have the capability of providing a response above a whole number then it is acceptable to use the current EDIL system to reflect that value. This means rounding up to the next whole number.

Conclusion

ETI would agree that DSUs could be identified into the two categories of 'Long-Runs' and 'Intermittent'. The questions posed throughout the paper do require separate responses for each of these categories, and recommendations should reflect that.

'Intermittent' DSUs have existing contractual arrangements with IDSs that may not be adjusted to reflect 'sharing' of reduce payments for grid imports. Note that there are additional costs to IDS in providing the reduction and this includes loss of production and/or recovery of production through additional work. The ability to financially cover any 'compensation' payment could be challenging and result in increased Offer prices to the market.

'Long-Runs' have an overall provision of demand reduction, and that benefit provided to the System may be covered by the Capacity payment, since it does require investment in that ability. All providers of energy balancing services, irrespective of their technology, have to make investment in their capabilities and are required to enter the T&SC and the CRM. Equal treatment requires payment for similar provision of capability.

ETI suggests that the 'Long-Runs' cover 'compensation' back to the Imperfections Charge fund and that 'Intermittent' DSUs do not. The level of 'compensation' by the 'Long-Runs' should equal any Balancing Market value incurred by the supplier.

ETI understands that a reduction in consumption results in reduced revenue to suppliers. The requirement to cover DSU energy payments means that suppliers need to fund such across all their customers. This however is mitigated by the balancing of the system by the 'Intermittent' DSUs at a price lower than the next expensive generator. It also can spread that benefit across all suppliers if the Imperfections Charge fund is utilised.

ETI expected the discussion over energy payments to DSUs to be limited to just that. It is unfortunate that the SEMC utilised this paper to air its wider grievances regarding demand response. Some would say that a number of the topics discussed should have been outside the scope of the consultation paper.