# VIOTAS Response to SEM 24 046

The issue of Demand Side Units ("**DSUs**") energy payments has been ongoing since the inception of the Integrated Single Electricity Market (the "**I-SEM**"), if not before. It was noted by the European Commission in their State Aid Approval for the Irish Capacity Mechanism (No. SA.44464 2017/N) (the **"State Aid Decision"**) and deemed to be an issue that the SEM Committee had to resolve "*once the I-SEM reforms are implemented*". Access to energy payments for DSUs has been a binding obligation under the Clean Energy Package, in particular having regard to Articles 3 & 6 of Regulation (EU) 2019/943 (the "**Regulation**") and Article 17(1), (2) and (3) of Directive (EU) 2019/944 (the "**Directive**") (together, the **"EU Law Provisions"**). The EU Law Provisions have been in force since 1 January 2020.

VIOTAS is now responding to SEM-24-046 (the "**Consultation**") in October 2024 – nearly five years after the obligations to grant DSUs energy payments became legally binding – as a result of an 'impact assessment' carried out by the SEM Committee on Mod_02_23, itself published nearly two years ago. Moreover, the Consultation focuses on an issue that is ancillary to the obligations placed on the State to grant DSUs energy payments – namely the optional measure of a compensation mechanism.

This Response will clearly set out the position of VIOTAS, which can be summarised as follows:

1. While seeking to address an optional measure as per Article 17(4) of the Directive, the Consultation has the effect of unlawfully delaying compliance with binding obligations under the EU Law Provisions. <u>The Consultation should therefore be revoked until such time as these obligations have been met.</u>
2. Much of the content of the Consultation is wholly inappropriate and misleading and should be corrected prior to the commencement of a new Consultation in relation to Article 17(4), once DSUs have been granted energy payments through the implementation of Mod_02_23.
3. The solution put forward by the SEM Committee does not meet the requirements of Article 17(4) and the draft Network Code for Demand Response (the "**NCDR**"), and therefore should be amended.

This Response ought to be seen in the context of the attempted dialogue in which VIOTAS has been trying to engage with the SEM Committee, to no avail. In this regard, we refer to our numerous letters, which have not received responses within the appropriate timeframes and which, when responded to, have been responded to inadequately. The amended solution put forward in Section 3 below is without prejudice to these communications and to VIOTAS's position that energy payments have been required for DSUs since 1 January 2020.

The final Section sets out our answers to the questions posed by the Consultation.

It should be emphasised at the outset that, in submitting this Response, VIOTAS fully reserves its position and all its rights, and its participation in the Consultation does not give rise to any concession as to the validity of the Consultation.

## 1. The Requirement to Implement DSU Energy Payments Prior to this Consultation

DSU energy payments are mandated by the EU Law Provisions, all of which were in force by 1 January 2020.

Pursuant to the EU Law Provisions, there is a clear obligation on the SEM Committee to ensure that DSUs are capable of participating in the market alongside generators in an equal manner. As recognised by previous SEM Committee consultations, this includes a requirement for access to energy payments by DSUs. In compliance with this, SEM-22-090 proposed a phased solution, Phase 1 of which involved implementation of the measure later approved by the Modifications Committee in Mod_02_23.

In this Consultation, as well as in other publications, the SEM Committee admits to having delayed this modification on the basis of an 'impact assessment' of the cost implications to the system of granting DSU energy payments. This is stated most clearly in SEM-24-064:

> "*This Modification [Mod_02_23] was subject to an impact assessment. This impact assessment showed that a significant majority of the impact on the TSOs' forecast of Imperfections Charges was due to broadly 'always on', or 'long-run', DSUs. Based on this impact assessment, the SEM Committee decided to amend the TSOs' submission such that the effect of energy payments to long-run DSUs was removed.*"

In addition, in the SEM Committee's "Update on decision SEM-22-090 'Enduring Solution to Enable Energy Payments in the Balancing Market for DSUs' and the Balancing Market Trading and Settlement Code Modification – Mod_02_23" on 8 December 2023, it was stated that:

> *"In light of these considerations and developments since SEM-22-090 was published the SEM Committee considers it appropriate to consult on solutions that will take account of the different modes of DSU participation"*

It is clear from the above statements that the SEM Committee is attempting to implement a measure such that some DSUs would not be granted energy payments in any meaningful way due to the costs associated with doing so, despite there being no provision in the EU Law Provisions for delaying or avoiding compliance on the basis of cost.

As a separate matter, in the Consultation, the SEM Committee proposes a mechanism designed to mitigate the cost of the obligations required by the EU Law Provisions. This mechanism ultimately arises pursuant to Article 17(4) of the Directive, which states that:

> "*Member States may require electricity undertakings or participating final customers to pay financial compensation to other market participants or to the market participants' balance responsible parties, if those market participants or balance responsible parties are directly affected by demand response activation*".

This optional compensation is separate from the mandatory obligations to ensure equal market treatment for DSUs under the EU Law Provisions. This is apparent from the use of the word "may", which is replaced by "shall" for all other provisions of the Article. Unlike the binding obligations arising under the EU Law Provisions, measures pursuant to Article 17(4) can be implemented at the discretion of the Member State. Therefore, the ongoing delay in meeting the obligations under the EU Law Provisions as a result of the intention to implement a measure under Article 17(4) is misconceived and unlawful. This is especially striking because a known, compliant, and approved measure exists in the form of Mod_02_23.

Another purported justification for the delay of Mod_02_23 is the more recent publication of the draft NCDR. While the NCDR is indeed relevant to Article 17(4), it remains in draft form. In any event, it does not and will not change the obligations placed on the State under the EU Law Provisions.

In addition to the EU Law Provisions, the Consultation ignores the clear and ongoing non-compliance of the current arrangements as to DSU energy payments with the State Aid Decision. The State Aid Decision concerned the Capacity Remuneration Mechanism (the **"CRM"**), which was acknowledged to require State Aid insofar as it would benefit capacity providers in receipt of option fees. Given the emphasis in the State Aid Decision on ensuring broad access to these benefits, it is not surprising that the Commission devoted a section to the *"Participation of demand response"*. It was therein noted that the exemption of DSUs from payback obligations in certain circumstances was *"acceptable as a temporary measure"* given that DSUs did not receive energy payments. However, the Commission expressly stated that *"the situation that DSUs cannot access energy payments needs to be remedied in the medium term"* and *"once the I-SEM reforms are implemented"*. In response to this, it was stated that *"the authorities have committed to end the exemption from payback obligations for DSUs as of the delivery period starting in October 2020"*, and this commitment was welcomed by the Commission.

Therefore, it is clear that it was a condition of the approval of the CRM on State Aid grounds that access to energy payments for DSUs would be provided after the transition period. While, technically, the exemption from payback obligations for DSUs has been removed (with energy payments implemented at times when difference payments would be required), it is still the case, almost seven years since the State Aid Decision, that full access to energy payments for DSUs has not been implemented as required under the said Decision. This is despite the requirement that this failure would be remedied in the *"medium term"* (which needs to be seen in the context of a measure which was envisaged in the State Aid Decision to be in place for ten years). In circumstances where this breaches a key condition of the State Aid approval of the CRM – in respect of which VIOTAS reserves its position – it is extraordinary that the Consultation seeks to further delay the implementation of energy payments.

In the context of the State Aid Decision, and the need for full compliance with the EU Law Provisions, as well as the optional nature of the measures outlined in Article 17(4), VIOTAS requests that:

1. The Consultation is revoked;
2. Mod_02_23 is implemented in full and without delay;
3. A new Consultation is issued, aimed at identifying the best solution for a measure under Article 17(4).

In issuing a new Consultation, the SEM Committee would also have the opportunity to correct many of the misleading statements made in SEM-24-046. These will be addressed in the next section.

## 2. Misleading Statements to Correct in the New Consultation

The SEM Committee's intentions in this Consultation are to form an appropriate compensation mechanism to reduce the cost of implementing energy payments for DSUs. Unfortunately, in its efforts to rationalise the solutions proposed therein and moreover to purport to justify its delay in implementing Mod_02_23, the SEMC misrepresents critical information on the operation, performance measurement, and settlement of DSUs. Given the general lack of familiarity of other market participants with the intricacies of demand response, it is inevitable that the majority of respondents will rely heavily on descriptions provided by the SEMC in the Consultation Paper and, in doing so, there is a high risk that their responses will be misguided.

These inaccurate statements were set out in previous correspondence from VIOTAS to the SEM Committee. We request that, in the new Consultation, the SEM Committee makes amendments with respect to the following matters:

a) The alleged distinction between DSUs based on their market participation;
b) The balance responsibility of DSUs; and
c) The description of unit bidding behaviour and the statement that the SEMC was unaware of this behaviour.

Each of these will be addressed in turn.

a) <u>The Alleged Distinction Between DSUs Based on Their Market Participation</u>

The Consultation frequently distinguishes between DSUs based on their usual market participation characteristics. The growing narrative that attempts to technically distinguish between "*long run*" and "*short run*" DSUs in the SEM is concerning and fundamentally incorrect. All units, including Generator Units ("**GUs**") and DSUs operate under the conditions and parameters set out by the Grid Code and Trading and Settlement Code ("**TSC**"). These parameters, largely the same for both GUs and DSUs, provide a framework for units to create specific values that distinguish them in the merit order. Terminology such as "*base load*" and "*peaking plants*" can be used as easy parlance when discussing the placement of units in this merit order as a result of the range of values they submit, but at no point, in either the Grid Code or the TSC, are these terms defined. Nor, in any documentation, is it specified that the values submitted under this framework could lead to differential treatment within the market. Similarly, the modes of participation such as "*long run*" are simply a result of the market scheduler ordering units according to their technical and price offers. Units with low price offering will be called upon by the TSO for longer durations than those with higher costs. This logic stands for both GUs and DSUs and is a fundamental principle in our market.

VIOTAS is also concerned by the sentiment expressed in Section 3.5 of the Consultation, in which the SEM Committee appears to question the applicability of the definition of demand response to "*long run*" DSUs. Fundamentally, by placing bids into the market, and making themselves available for TSO instruction, all units become subject to the market scheduler, which determines the outcome. For DSUs, depending on their complex offer data, this gives rise to different operating profiles as described in the Consultation. However, each and every unit changes its consumption patterns in response to this market scheduler. In this context, it is important to note that the Directive defines demand response as:

*“the change of electricity load by final customers from their normal or current consumption patterns in response to market signals, including in response to time-variable electricity prices or incentive payments, or* ***in response to the acceptance of the final customer's bid to sell demand reduction or increase at a price in an organised market*** *as defined in point (4) of Article 2 of Commission Implementing Regulation (EU) No 1348/2014, whether alone or through aggregation”.*

Given that DSUs respond to market signals, or TSO instructions, therefore changing their consumption patterns as a result of the acceptance of a bid to sell demand reduction or increase in an organised market, we can conclude that each DSU participates as demand response.

As a result, the attempt by the SEM Committee to use colloquial market parlance as a basis for technical or regulatory distinction is flawed and should be corrected in the new Consultation.

b) Balance Responsibility of DSUs

Balance responsibility refers to, as described in the Electricity Balancing Guideline (the “**EBGL**”), the obligation of Balance Responsible Parties (“**BRPs**”) to ensure that their scheduled electricity supply or consumption matches the actual quantities produced or consumed.

The Consultation Paper twice states that DSUs are exempt from balance responsibility, providing the following rationale in Section 4.3 under the heading “Metering”:

> *“The SEM Committee is concerned that continuing to set DSU Metered Quantity equal to Dispatch Quantity and effectively exempting DSUs from balance responsibility is potentially inconsistent with Article 5(1) of the Electricity Regulation.”*

This statement is demonstrably incorrect and misleading. It directly contradicts previous SEM Committee determinations, despite no other related factors having changed in the interim, such as SEM-20-027 in which the SEM Committee concludes that the SEM is *“already compliant with CEP requirements on balance responsibility”* when assessed in relation to Article 5 of the Regulation. The same paper explicitly concluded that DSUs are balance responsible and that no changes to the SEM were required to enable balance responsibility. Similarly, SEM Committee decision paper SEM-20-088 confirmed that the current rules regarding aggregation were compliant with Articles 6 and 7 of the Regulation and that no market changes were required in relation to aggregation or to enable aggregators to become balance responsible.

Secondly, the measurement of demand response inevitably relies upon a baseline methodology to serve as a proxy for the counterfactual (i.e. the absence of activation), thus creating a proxy for response and therefore balance responsibility. It is widely acknowledged that this is complicated, and it cannot be described as accurate, only reasonable.

In the SEM, under the Grid Code, DSU aggregators are obliged to continually update the TSO with compliant values that reflect their real-time capability. Where a DSU is dispatched and their capability differs from the value to which they are dispatched, the DSU will update the TSO on its actual capability and the TSO will update its dispatch instruction accordingly. For example, if a DSU was procured to deliver 20 MW in the day-ahead market, but at the time of delivery was only available for 18 MW, the DSU would be obliged to declare appropriately and would be dispatched to 18 MW accordingly – leaving the DSU short by 2 MW for which it should be balance responsible. As such, contrary to the SEM Committee statement, Dispatch Quantity is an accurate proxy for Metered Generation and ensures a reasonable level of balance responsibility for DSUs.

Finally, while the SEM Committee statement that "*continuing to set DSU Metered Quantity equal to Dispatch Quantity and effectively [exempts] DSUs from balance responsibility"* is demonstrably incorrect, VIOTAS would argue that, to the contrary effect, the continued inclusion of the TSSU in the settlement algebra for a DSU participant does, in effect, negate the balance responsibility of the DSU participant. Building on the previous example where the DSU found itself 2 MW short in the market and subject to imbalance **charges** for this quantity, the DSU participant's corresponding TSSU would find itself 2 MW long in the market and subject to imbalance payments for this quantity. As a result, the existence of the TSSU financially nullifies the balance responsibility of the DSU. With this in mind, it would seem that the solution approved in Mod_02_23 – removing the TSSU – would leave DSUs fully balance responsible.

We request that the SEM Committee clarify the statements made regarding balance responsibility in the new Consultation Paper to reflect the above points.

c) *Description Of Unit Bidding Behaviour and Statement That the SEMC Was Unaware of This*

In the Consultation Paper, the SEM Committee states that the proportion of costs associated with the measure approved in Mod_02_23 was not apparent during the decision-making process. However, as stated in the Final Recommendation Report for Mod_02_23, "*The TSO Member advised that following a review of data for the year 2022, it was estimated that, all things remaining equal, there would be an additional imperfection cost of between €60 - €65 million. This amount would not be proportionately distributed with only a handful of the 49 units registered in the observed period receiving the vast majority of it due to their specific market conditions. The TSO is aware that the Market Monitoring Unit is reviewing the data of these units.*"

These 'market conditions' or bidding behaviours have been well documented and discussed, including in information note SEM-18-158. As stated in the Final Recommendation Report of Mod_02_23, the Market Monitoring Unit - operating as a part of the Regulatory Authority - has reviewed these behaviours, well in advance of either consultation on granting DSUs energy payments. The operation of some DSUs, in line with market rules that apply to all units, is in response to the market incentives for all units to have low cost, long duration characteristics. Section 3.6 of the Consultation sets out the practices of some DSUs in a way that, to a reader that may not understand the commonality of these practices across the industry, would make it seem that these market rules are unique to DSUs. The submission of negative decremental bid prices, where cost reflective as mandated by BCOP, and the concept of a DSU being paid to not reduce demand, should be seen as no less of a valid market outcome than a generator being paid not to generate, which they often do for various reasons; both are perfectly rational market outcomes in certain scenarios. As such, any change in market rules regarding decremental bids should be applied to all units.

In summary, these repeated errors and misleading statements that permeate the Consultation Paper mispresent the fundamental point that implementing Mod_02_23 would lead to compliance with the EU Law Provisions and that Mod_02_23 was approved by the Modifications Committee which was informed of all relevant matters. Therefore, we request that the SEM Committee implement Mod_02_23 without delay and issue a new Consultation with these amendments to identify an appropriate mechanism under Article 17(4).

## 3. The fundamental issues with the Revised Phase 1 Solution

Having regard to the above points, VIOTAS makes no concession as to the validity of the Consultation, and regards the Consultation as fundamentally flawed. It calls again on the SEM Committee to remedy these flaws.

Strictly without prejudice to the objections raised above, VIOTAS makes the following points in relation to the Revised Phase 1 Solution which is proposed in the Consultation.

VIOTAS does not object to the concept of a supplier compensation mechanism in accordance with Article 17(4) of the Directive, as an interim measure prior to perimeter correction, provided that it does not delay or avoid the implementation of binding obligations under the EU Law Provisions. However, we have several concerns with the proposed Revised Phase 1 Solution. In light of these, we request that the SEM Committee review its Revised Phase 1 Solution, ensuring that it is as close to compliance with Article 17(4) & draft Article 55A of the EBGL as proposed by ACER through the NCDR. These Articles, although outlining an optional measure, set out strict requirements that such a measure is subject to, if implemented.

What the SEM Committee is proposing is an indirect (via the imperfections charge fund), one-way compensation mechanism from DSU service providers to suppliers based on a proxy for the average retail energy price. The Revised Phase 1 Solution falls short of meeting the requirements for such a measure in several aspects.

Article 17(4) of the Directive states:

*"Member States* ***may*** *require electricity undertakings or participating final customers to pay financial compensation to other market participants or to the market participants' balance responsible parties****, if those market participants or balance responsible parties are directly affected by demand response activation****. Such financial compensation shall not create a barrier to market entry for market participants engaged in aggregation or a barrier to flexibility. In such cases, the* ***financial compensation shall be strictly limited to covering the resulting costs incurred by the suppliers of participating customers or the suppliers' balance responsible parties during the activation of demand response****."*

Article 22a(3) of the NCDR proposed by ENTSO-E & EU DSO Entity states:

*"Financial transfer mechanism shall be applicable in the event of upward activation and of downward activation,* ***encompassing possible financial flows respectively from the service provider to the supplier and vice versa."***

Article 55A of the EBGL proposed by ACER through the NCDR states:

"*1. Each TSO shall calculate for each imbalance settlement period, for each imbalance area,* ***a financial transfer for each balance responsible party for which a correction in the final position has been calculated*** *pursuant to Article 54(4)(1a). [...]*

*2.* ***If, in addition to the financial transfer mechanism pursuant to paragraph 1****, the Member State has established a financial compensation pursuant to Article 17(4) of Directive 2019/944/EU,* ***each TSO shall calculate this financial compensation for the relevant balance responsible parties*** *pursuant to Article 18(6)(f).*

*3. The financial compensation pursuant to paragraph 2 shall:*

*a. encompass the reimbursement of **specific, verifiable additional costs directly associated with the demand response activation** not already covered by the financial transfer pursuant to paragraph 1; and*

*b. include the **costs incurred by the supplier**."*

The emphasis added in the above provisions show aspects where the Revised Phase 1 Solution fails to meet the requirements for a compensation mechanism, which are explained further in the following sub-sections.

*a. The indirect nature of the use of the Imperfection Charge Fund*

As stated in Article 17(4), the compensation mechanism shall only be applicable for suppliers of participating customers (or their BRPs), rather than all suppliers. Given that the Imperfections Charge encompasses all suppliers, this does not meet the requirements of Article 17(4).

Furthermore, the phrase '*directly affected by demand response activation'* precludes the use of the Imperfections Charge for two reasons. Firstly, the Imperfections Charge is fundamentally an indirect tool used to recoup system charges that cannot be directly attributed to specific actions (such as demand response activations). Therefore, its use for a compensation mechanism is inappropriate given the wording of Article 17(4). Secondly, all suppliers, although included in the Imperfections Charge, and therefore indirectly paying for DSU energy payments, are not directly affected by a demand response activation, but rather by the cost of granting DSUs energy payments. This is a key distinction, as the intention of the Directive is to clearly allocate balance responsibility through perimeter correction, which this blunt, indirect measure fails to achieve.

*b. The lack of limitation to the 'resulting costs of the suppliers of participating customers'*

A fundamental aspect of Article 17(4), and indeed the NCDR, is that the compensation is "*strictly limited*" to "*specific, verifiable additional costs directly associated with the demand response activation*". This requires attributing the activation to the final customer's supplier, and determining the exact cost incurred as a result. This should not include possible margins, or any tariffs not incurred as a result of the activation (e.g. TUoS, DUoS, Loss Factor etc. in the case of energy not being consumed). Without this specificity, the Revised Phase 1 Solution risks overcharging DSUs through this compensation mechanism, and falsely attributing costs through its blanket approach.

*c. The need for a financial transfer mechanism prior to financial compensation*

Article 55a of the proposed EBGL text, as amended through the NCDR, states the need for a financial transfer mechanism prior to the compensation mechanism as proposed in the Consultation. This financial transfer mechanism appears to be directly referring to a perimeter correction model, in which imbalance volumes are correctly attributed, and a financial payment is made accordingly. Only in addition to this, if still necessary, would a financial compensation model under Article 17(4) of the Directive be valid.

*d. The lack of provision for financial flows to both the supplier <u>and</u> service provider*

As specified in Article 22a(3) of the NCDR, and implied by the wording of draft Article 55a of the EBGL, financial flows must be able to flow both in the direction of the supplier from the service provider, and vice versa. The supporting documents lay out two cases in which either could happen:

- *"CASE A - systems operators send a request for an upward activation to a service provider who provides the service by decreasing the consumption of its contracted asset. This activation causes the forgone loss for a supplier under the assumption that supplier previously purchased that energy. In this case service provider will compensate the supplier.*
- *CASE B – systems operators send a request for a downward activation to a service provider who provides the service by increasing the consumption of its contracted asset. In this case of increased consumption, supplier will bill to its customer more energy and supplier will have to transfer the part of its revenues to the concerned service provider."*

Given that TSO instructions can result in DSUs being dispatched upwards or downwards relative to their *ex-ante* market position, the compensation mechanism must be able to account for flows in either direction. The Revised Phase 1 Solution fails to allow for this, leaving any supplier margins intact in the event of an upward activation, which therefore renders the Revised Phase 1 Solution noncompliant with the provisions highlighted above.

*Summary:*

In summary, these issues as set out above preclude the Revised Phase 1 Solution from being a compliant solution with regard to Article 17(4) of the Directive. Furthermore, the Revised Phase 1 Solution would have a significant negative impact on some DSUs and undermine the viability of the associated end-users' continued participation in the market via a DSU with their on-site generation assets. This would have several consequences for the system, including:

- a reduced financial incentive for onsite generation, thereby reducing capacity available to the system;
- a reduction in the volume of behind-the-meter generation visible to / controllable by the TSOs;
- a reduced incentive to be operating at times of system stress; and
- no incentive for behind-the-meter generation assets to be curtailed at times of high renewable penetration, leading to greater levels of dispatch down of renewables.

There are also consequences to aggregators and final customers participating in DSUs. The most striking of these is the inability of aggregators to fulfil capacity obligations held out to 2029 given the negated value of so called "*long run*" units. For final customer participating in DSUs, they will lose the revenue that helps to offset high energy costs, as well as an outlet to support the grid. VIOTAS fundamentally believes all forms of DSU benefit the system and end users, and the Revised Phase 1 Solution would remove this benefit.

As result of these failures to meet the requirements, as well as the implied loss of ability for some DSUs to fulfil capacity obligations, the current Consultation cannot proceed with this solution as a proposed measure. Therefore, a new Consultation should be drawn up with measures that are much closer to compliance with Article 17(4) and the NCDR/ EBGL as drafted by ENTSO-E, EU DSO Entity, and amended by ACER, once the binding obligations under the EU Law Provisions have been met through the implementation of Mod_02_23. A potential such measure is outlined in the next section.

## 4. A potential solution to meet the requirements

For the reasons outlined above, the Revised Phase 1 Solution proposed in the Consultation is not compliant with EU law and the Consultation itself is fundamentally flawed in light of the requirements of the EU Law Provisions. Further, it is noted that the SEM Committee continues to erroneously conflate its obligations under the EU Law Provisions with the optional compensation measure under Article 17(4), which has had the effect of unlawfully delaying the implementation of Mod_02_23.

Given the approach of the SEM Committee to date, the lawfulness of which is not accepted, and strictly without prejudice to VIOTAS's legal rights and, in particular, its right to rely on the Regulation and Directive in full, VIOTAS proposes the following measures in the case that the SEM Committee refuses to implement Mod_02_23 without a compensation mechanism under Article 17(4). These measures may operate on a workable interim basis and are proposed solely in an effort to participate in this consultation process and to prevent further delay to the implementation of Mod_02_23. However, in proposing these measures, VIOTAS fully reserves all its legal rights, and in particular, as already noted, its right to rely on the EU Law Provisions.

Further, and for the avoidance of doubt, VIOTAS does not believe that this solution is entirely compliant with the requirements set out above, however, if the SEM Committee is determined to implement a measure of this kind, it is suggested that the solution outlined may serve as a workable interim measure. We are also of the view that the measures proposed below should be consulted upon in full following the implementation of Mod_02_23.

While the Consultation remained vague as to the specifics of the compensation price, the methodology for calculation, and settlement, VIOTAS notes that in Section 3.5, the SEM Committee proposes some options for determining Supplier Compensation Price (the "**PCOMP**") including "*using some form of average price, which could be, say, a three-month rolling average of the Day-Ahead Market baseload price or mid-merit price, recalculated each month, plus the Capacity Charge and the Imperfections Charge*" (the "**Proposed Option**").

VIOTAS's proposed solution builds on this option within the Revised Phase 1 Solution, while correcting some of the errors, as well as expanding to cover the practicalities of implementing such a solution. This includes calculating the PCOMP by starting with the Average Day Ahead Market (the "**DAM**") price, the use of a 90-day rolling average, the necessary settlement mechanisms, the interaction with reliability option difference charges, and the inclusion of some proxy for the benefits of demand response for the system.

1. *The use of the DAM Price*

Several options were put forward by the SEM Committee as to which price to base PCOMP on. One particularly concerning proposal was to calculate the supplier compensation price as an administratively determined proxy for the average retail price. While this would elegantly solve the missing money problem for high cost DSUs (colloquially "*short run*" units), as set out above it would radically undermine the viability of low cost DSUs (colloquially "*long run*" units). VIOTAS would like to reiterate that the market rules applicable for all units, including the market scheduler, are the core reason for differing participation modes, rather than any distinction between DSUs and that nothing in this section should be construed as acceptance by VIOTAS of the legitimacy of this distinction.

In the Section above, we refer to the requirement to limit compensation to the costs incurred by suppliers as a direct result of a DR activation. Given the nature of DR activations, the supplier does not incur many of the costs that make up the retail price such as TUoS, DUoS, Loss Factor, Capacity Charge, Imperfections Charge etc. Therefore, the only costs that are genuinely incurred by suppliers in the event of an activation is the price they paid for the energy that was not consumed. Even this assumes that these suppliers are unable to resell this energy for the given time period.

With this in mind, taking the Day Ahead Price only as a proxy for the energy price, as per the Proposed Option quoted above, is the only fair basis on which to calculate the supplier compensation price.

This is especially true when considering the extensive supplier windfall that remains intact with this mechanism, as recognised in Section 2.2 of the Consultation: "*It was recognised that this Phase 1 solution would result in concerns of double-counting, in that demand reduction would result in both savings in purchase costs for the supplier as well as explicit payments to the DSU*". While the extensive supplier windfall will be removed by the envisaged Phase 2 solution which will correctly adjust the imbalance volumes between the DSU aggregator and impacted suppliers, this remains intact with the proposed interim mechanism due to the stated complexity of implementing the proper solution as per Phase 2.

Not only will this be closer to compliance with the relevant provisions, including the requirement for these mechanisms not to be an undue barrier for these units, but it will also ensure that "*long run*" units remain viable, which is imperative in the context of these unit's capacity contracts. This appears to be a stated goal of the Consultation (Section 3.5 states "'*Long run DSUs' neither lose, nor benefit, significantly from differences between the supplier compensation payment and the average costs of purchasing from the SEM*"). Alternatively, any solution that undermines the value of these units must be implemented with a four-year time horizon, when these units' capacity obligations have expired.

Furthermore, VIOTAS's solution is more suitable, as it remains entirely under the TSC, and therefore can be executed by SEMO – given the use of the Day Ahead Price rather than any other proxy.

2. *The use of a 90-day rolling average*

The following issues are vital to ensure that all DSUs remain viable under this mechanism and prevent scenarios in which they are exposed to liquidity issues, or extensive losses as a result of the design.

The use of a 90-day rolling average DAM price is essential to mitigate the volatile nature of the wholesale prices. Using a shorter averaging period would blunt the price signal to so called "short run" units during periods of scarcity, once the supplier compensation is netted off earned revenue, whereas the use of a longer averaging period may risk large liquidity exposures that do not take account of changing seasonal prices. VIOTAS believes using a 90-day rolling average period to determine the PCOMP strikes the most appropriate balance.

It is also important to use a 90-day rolling period, calculated weekly, *ex-ante* for each Settlement Week, as opposed to a calendar month period.

*3. The use of weekly settlement mechanisms*

While not addressed in the Consultation, VIOTAS believes the most appropriate mechanism for settlement is the netting of the supplier compensation in the weekly settlement, prior to payment. This mitigates excessive repayments, as well as unnecessary payments followed by repayments. The weekly settlement also prevents liquidity issues. In the same way as make whole payments are calculated at the end of each settlement week, any supplier compensation charges would be calculated weekly and effectively netted off the energy revenue received by each unit at source.

*4. The use of the lower of the strike price and the 90-day rolling average*

It is essential that the supplier compensation mechanism is designed so as to avoid any negative interaction with reliability option difference charges. It is important this is designed in such a way that all DSUs have appropriate access to covering revenues to mitigate their difference charge exposure, and the supplier compensation payments do not erode this. A key concern of VIOTAS is the possibility of PCOMP rising above the reliability option strike price for any period. While unlikely, it is important that all such scenarios are carefully factored into the design. If PCOMP rose above the strike price and there was a reliability option event, this would lead DSUs to be paying back twice for any energy payment in excess of the strike price, which is clearly not appropriate. As such, the PCOMP must be set to the lower of the strike price and the 90-day rolling average DAM price.

*5. The inclusion of a proxy for the benefits of DR on a per MWh basis*

It is also important that the wider full system benefits of demand response are taken into account when calculating supplier compensation payments, as per Article 17(4) of the Directive, Article 55a(4) and (5) of the draft EBGL revision, and Article 22(b) of the NCDR. Such benefits are the lower wholesale prices as a result of DR activations, the lower network tariffs (especially due to units with on-site generation), lower system operation costs (especially due to units with on-site generation), and many more.

While VIOTAS understands the complicated nature of doing so, the SEM Committee could use a proxy value for these benefits based on historic data and apply this on a per MWh basis to the PCOMP, reducing it by the appropriate value.

*Conclusion*

In conclusion, while VIOTAS strongly believes that the SEM Committee should implement Mod_02_23 without delay, and only subsequently consult upon any solution in respect of supplier compensation, it is noted that the SEM Committee continues to conflate these issues. As such, and without prejudice to our position as set out in this Response, we submit that if a measure were to be imposed in conjunction with Mod_02_23, it should be in accordance with the principles set out above. In particular, the supplier compensation price should be determined as the lesser of the reliability option strike price and the 90-day rolling average DAM price without the addition of any further charges or costs and including a €/MWh reduction to reflect the full system benefits of demand response.

The relevant provisions of EU law, both in draft and in force, are clear and prescriptive as to the costs that may be included in the compensation price. These do not include costs that have not been incurred as a result of the non-delivery of energy. Therefore, VIOTAS contends that only the DAM price should be included as the starting point for the PCOMP, which should also be adjusted for the net benefits brought by demand response on a per MWh basis. Furthermore, key practical elements must be considered to prevent liquidity issues, and unintended losses for DSUs in certain scenarios.

## 5. Conclusion

The obligation of the SEM Committee to ensure equal market treatment of DSUs, arising under the EU Law Provisions, has been in force since 1 January 2020. Energy payments are therefore long overdue. The recent conflation by the SEM Committee of this obligation with the optional measure outlined in Article 17(4) of the Directive has resulted in a further delay in meeting these obligations. VIOTAS urges the SEM Committee to decouple these issues and implement Mod_02_23 without delay. Once implemented, the optional measure desired by the SEM Committee can be consulted upon and ultimately put in place.

Notwithstanding this - **and without prejudice to our position regarding the need for immediate implementation of measures compliant with the EU Law Provisions** - if, for any reason, the SEM Committee refuses to decouple these measures, we have suggested a possible solution that would at least reduce the potential harm to some DSUs, rather than further delaying the implementation of Mod_02_23 through extensive consultation on both issues.

We also request that the statements made in the Consultation which are demonstrably false are corrected, preferably in the new Consultation proposing measures compliant with Article 17(4), or at least in a SEM Committee information note or other publication. This is imperative as these statements greatly hinder our industry's reputation, future standing in the market, and will influence the responses received to the Consultation.

## 6. Consultation Questions

It is the position of VIOTAS that many of the Consultation questions are not relevant to the issue of granting DSUs energy payments and should not be included in this Consultation. Furthermore, many issues have been subject to previous dialogue between the industry and the TSO, and do not warrant further consultation. These questions merely distract from the ongoing non-compliance of the SEM with the EU Law Provisions.

The below responses are provided strictly without prejudice to the points made in the above sections of this Response, as well as without prejudice to VIOTAS's legal rights and in particular its right to rely on the terms of the Regulation and the Directive in full. We believe the questions relevant to the mechanism should be re-consulted upon with corrections made to the misleading statements and to the solution proposed, once Mod_02_23 has been implemented. It should also be recognised that the interim solution is not compliant with EU law.

Nonetheless, in an effort to participate with the Consultation and while entirely reserving our position and all our legal rights, we have responded to the following questions.

**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.**

Model 1 (No DSU Energy Payments) – VIOTAS agrees with the description of this model, as well as the recognition of the need to change to one in which DSUs are actually compensated equal to generators for the energy provided to the system.

Model 2 (DSU Energy Payments with supplier billing) – VIOTAS largely agrees with the description of this model and contends that, along with Model 3, these are the only models in which the SEM would be fully compliant with the EU Law Provisions. However, the statement "*There will need to be a side payment from the DSU to the customer to cover these costs*" implies that there is a misunderstanding by the SEM Committee of the current arrangements whereby DSU aggregators pass through a large portion of any revenue they receive to the end-consumer.

Model 3 (DSU Energy Payments with supplier compensation) – VIOTAS somewhat agrees with the description of this model, however, a key point is misrepresented - DSU aggregators would not seek any payments from participants, regardless of their savings, and always shares the revenue earned. However, we agree that if done correctly, directly attributing the demand reduction to the correct supplier and using the correct PCOMP, then this could be a viable measure. This also assumes no bilateral contract would be needed between the aggregator and the supplier, which would set back the industry considerably, as well as being inconsistent with the requirement Article 17.3(a) of the Directive, which states that an aggregator must not require the consent of a supplier to work with their customer.

Revised Phase 1 Solution – VIOTAS objects to the Revised Phase 1 Solution. This solution attempts to implement the optional measure as set out in Article 17(4) of the Directive and expanded upon in Articles 22a and 22b of the draft NCDR, and Article 55a of the EBGL (amended through the NCDR as proposed by ACER). While the implementation of the measure is optional, the structure of the measure, if implemented, has strict requirements to fulfil.

Several aspects of the Revised Phase 1 Solution fall short of meeting these requirements. The SEM Committee is proposing an indirect (via the imperfections charge fund) one way compensation mechanism from DSU service providers to suppliers based on a proxy for the average retail energy price. However, these obligations require a direct, two-way measure that is limited to the costs incurred during the activation.

Furthermore, the proposed solution leaves suppliers facing the imbalance (their volumes are untouched, and they are not otherwise financially adjusted, which appears to be contrary to the requirements of the Clean Energy Package) and demand response providers instead repay into the imperfections pot a revenue estimated to be equivalent to the retail-tariff-based savings the customer has made from having reduced consumption. This appears to tackle the "double counting" concerns but does not resolve imbalance costs.

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

No, VIOTAS contests many of the statements made regarding the description and analysis of so-called "*Long Run DSUs*". As expressed in the main body of this response, the persistent use of the term "*long run DSU*" is concerning, as the SEM Committee appears to be using it to draw distinctions between units that do not exist.

The growing narrative that delineates between 'modes of participation' of units in the SEM is concerning and fundamentally incorrect. All units, including GUs and DSUs operate under the conditions and parameters set out by the Grid Code and TSC. These parameters, largely the same for both GUs and DSUs, provide a framework for units to create specific values that distinguish them in the merit order. Terminology such as Base Load and Peaking Plants can be used as easy parlance when discussing the placement of units in this merit order as a result of the range of values they submit, but at no point, in either the Grid Code or the TSC, are these terms defined. Nor, in any documentation, is it specified that the values submitted under this framework could lead to differential treatment within the market. Similarly, the 'modes of participation' such as '*long run*' are simply a result of the market scheduler ordering units according to their technical and price offers. Units with low price offering will be called upon by the TSO for longer durations than those with higher costs. This logic stands for both GUs and DSUs and is a fundamental principle in our market.

Furthermore, in the Consultation Paper, the SEM Committee implies that some DSU behaviour was unknown to them, as well as being unique to DSUs. However, the operation of some DSUs, in line with market rules that apply to all units, is in response to the market incentives for all units to have low cost, long duration characteristics. Section 3.6 of the Consultation Paper sets out the practices of some DSUs in a way that, to a reader that may not understand the commonality of these practices across the industry, would make it seem that these market rules are unique to DSUs. The submission of negative decremental bid prices, where cost reflective as mandated by BCOP, and the concept of a DSU being paid to not reduce demand should be seen as no less of a valid market outcome than a generator being paid not to generate; both are perfectly rational market outcomes in certain scenarios.

VIOTAS is also concerned with the sentiment expressed in Section 3.5 of the Consultation, in which the SEM Committee appears to question the applicability of the definition of demand response to '*Long Run*' DSUs. Fundamentally, by placing bids into the market, and making themselves available for TSO instruction, all units become subject to the market scheduler which determines the outcome. For DSUs, depending on their complex offer data, this gives rise to different operating profiles as described in the consultation. However, each and every unit changes its consumption patterns in response to this market scheduler. In this context, it is important to note that the Directive defines demand response as:

*"the change of electricity load by final customers from their normal or current consumption patterns in response to market signals, including in response to time-variable electricity prices or incentive payments, or* ***in response to the acceptance of the final customer's bid to sell demand reduction or increase at a price in an organised market*** *as defined in point (4) of Article 2 of Commission Implementing Regulation (EU) No 1348/2014, whether alone or through aggregation".*

Given that DSUs respond to market signals, or TSO instructions, therefore changing their consumption patterns as a result of the acceptance of a bid to sell demand reduction or increase in an organised market, we can conclude that each DSU participates as demand response.

Furthermore, the Revised Phase 1 Solution would have an extensive negative impact on some DSUs and undermining the viability of the associated end-users continued participation in the market via a DSU with their on-site generation assets. This would have several consequences to the system, including:

- a reduced financial incentive for onsite generation, thereby reducing capacity available to the system;
- a reduction in the volume of behind-the-meter generation visible to / controllable by the TSOs;
- a reduced incentive to be operating at times of system stress; and
- no incentive for behind-the-meter generation assets to be curtailed at times of high renewable penetration, leading to greater levels of dispatch down of renewables.

**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.**

No – the incorporation of the supplier compensation payment reduces the net cost of granting DSUs energy payments but does not address the missing money problem for DSUs. Nor does it resolve imbalance costs or leave suppliers balance responsible.

What is described in the consultation paper as a "missing money" problem (not the usual meaning given to this phrase) is solved simply by providing energy payments to DSUs, as required by the Clean Energy Package. Supplier compensation payments have nothing to do with it.

The money that is really missing is due to the lack of perimeter correction for suppliers. Essentially, in the status quo, suppliers are receiving the benefits of the DSU's actions, instead of the DSUs and customers. Introducing the necessary energy payments ("Phase 1") solves the problem for DSUs, but still leaves suppliers with these undeserved windfall gains. Phase 2 resolves this issue by correcting suppliers' perimeters to remove the windfall gains.

It is the introduction of perimeter correction for suppliers in Phase 2 that leads to the need for supplier compensation payments: the payment directly relates to the volume of energy transferred in the perimeter correction.

Perimeter correction appears to be the only mechanism that satisfies the requirements set out under Article 17(4) and the draft NCDR.

**Q4**

**(A) 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.**

No, using the Imperfections Charge fund is not appropriate as it:

a. Constitutes an indirect payment by DSUs to all suppliers;
b. Has no way of determining the specific, verifiable costs incurred as a result of an activation;
c. Appears to precede the Financial Transfer Mechanism (such as perimeter correction) required by Article 55a of the Draft EBGL;
d. Leaves supplier's savings intact; and
e. Cannot flow in both directions (from service provider to supplier and vice versa).

These make it non-compliant with provisions of EU law as below.

Article 17(4) of the Directive states:

*"Member States **may** require electricity undertakings or participating final customers to pay financial compensation to other market participants or to the market participants' balance responsible parties**, if those market participants or balance responsible parties are directly affected by demand response activation**. Such financial compensation shall not create a barrier to market entry for market participants engaged in aggregation or a barrier to flexibility. In such cases, the **financial compensation shall be strictly limited to covering the resulting costs incurred by the suppliers of participating customers or the suppliers' balance responsible parties during the activation of demand response**."*

Article 22a(3) of the NCDR, proposed by ENTSO-E & EU DSO Entity, states:

*"Financial transfer mechanism shall be applicable in the event of upward activation and of downward activation, **encompassing possible financial flows respectively from the service provider to the supplier and vice versa."***

Article 55A of the EBGL, proposed by ACER through the NCDR, states:

*"1. Each TSO shall calculate for each imbalance settlement period, for each imbalance area**, a financial transfer for each balance responsible party for which a correction in the final position has been calculated** pursuant to Article 54(4)(1a). [...]*

*2. **If, in addition to the financial transfer mechanism pursuant to paragraph 1**, the Member State has established a financial compensation pursuant to Article 17(4) of Directive 2019/944/EU, **each TSO shall calculate this financial compensation for the relevant balance responsible parties** pursuant to Article 18(6)(f).*

*3. The financial compensation pursuant to paragraph 2 shall:*

*a. encompass the reimbursement of **specific, verifiable additional costs directly associated with the demand response activation** not already covered by the financial transfer pursuant to paragraph 1; and*
*b. include the **costs incurred by the supplier**."*

The emphasis added in the above provisions show aspects where a supplier compensation payment through the Imperfections Fund Charge would fail to meet the requirements of a potential compensation mechanism, which are explained further in the following sub-sections.

a. *The indirect nature of the use of the Imperfection Charge Fund*

As stated in Article 17(4), the compensation mechanism shall only be applicable for suppliers of participating customers (or their BRPs), rather than all suppliers. Given the Imperfections Charge encompasses all suppliers, this does not meet the requirements of Article 17(4).

Furthermore, the phrase '*directly affected by demand response activation'* precludes the use of the Imperfections Charge for two reasons. Firstly, the Imperfections Charge is fundamentally an indirect tool used to recoup system charges that cannot be directly attributed to specific actions (such as demand response activations). Therefore, its use for a compensation mechanism under is inappropriate given the wording of Article 17(4). Secondly, all suppliers, although included in the Imperfections Charge and therefore indirectly paying for DSU energy payments, are not directly affected by a demand response activation, but rather the cost of granting DSUs energy payments. This is a key distinction, as the intention of the Directive is to clearly allocate balance responsibility through perimeter correction, which this blunt, indirect measure fails to achieve.

b. *The lack of limitation to the 'resulting costs of the suppliers of participating customers'*

A fundamental aspect of Article 17(4), and indeed the NCDR, is that the compensation is "*strictly limited*" to "*specific, verifiable additional costs directly associated with the demand response activation*". This requires attributing the activation to the final customer's supplier and determining the exact cost incurred as a result. This should not include possible margins, or any tariffs not incurred as a result of the activation (e.g. TUoS, DUoS, Loss Factor etc. in the case of energy not being consumed). Without this specificity, the Revised Phase 1 Solution risks overcharging DSUs through this compensation mechanism, and falsely attributing costs through its blanket approach.

c. *The need for a financial transfer mechanism prior to financial compensation*

Article 55a of the proposed EBGL text, as amended through the NCDR, states the need for a financial transfer mechanism prior to the compensation mechanism as proposed in the Consultation. This financial transfer mechanism appears to be directly referring to a perimeter correction model, in which imbalance volumes are correctly attributed, and a financial payment is made accordingly. Only in addition to this, if still necessary, would a financial compensation model under Article 17(4) of the Directive be valid.

d. *The lack of provision for financial flows to both the supplier <u>and</u> service provider*

As specified in Article 22a(3) of the NCDR, and implied by the wording of draft Article 55a of the EBGL, financial flows must be able to flow both in the direction of the supplier from the service provider, and vice versa. The supporting documents lay out two cases in which either could happen;

- *"CASE A - systems operators send a request for an upward activation to a service provider who provides the service by decreasing the consumption of its contracted asset. This activation causes the forgone loss for a supplier under the assumption that supplier* *previously purchased that energy. In this case service provider will compensate the supplier.*

- *CASE B – systems operators send a request for a downward activation to a service provider who provides the service by increasing the consumption of its contracted asset. In this case of increased consumption, supplier will bill to its customer more energy and supplier will have to transfer the part of its revenues to the concerned service provider."*

Given that TSO instructions can result in DSUs being dispatched upwards or downwards relative to their ex-ante market position, the compensation mechanism must be able to account for flows in either direction. The Revised Phase 1 Solution fails to allow for this, and therefore it is rendered non-compliant with the above provisions.

**(B) 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 SEM Committee seem to imply that the granting of energy payments would unduly advantage DSUs unless a compensation mechanism is brought in. This is incorrect, as granting energy payments simply puts demand response on par with generators, while any supplier compensation payment reduces the cost of the measure for all end consumers.

Assuming the SEM Committee is committed to achieving the Climate Action Plan targets for flexible demand, they should be incentivising end-consumers to become involved in demand response, by granting energy payments, therefore increasing the revenue of DSUs.

**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.**

The prescriptive nature of Article 17(4), the FGDR, and the NCDR on the costs applicable for any compensation mechanism must be observed in any answer to this question, and VIOTAS strongly believes that the Consultation should have set out the following parameters prior to proposing this question.

Article 17(4) of the Directive states:

*[...] "financial compensation shall be **strictly limited to covering the resulting costs incurred** by the suppliers of participating customers or the suppliers' balance responsible parties during the activation of demand response." [...]*

Article 22b of the NCDR, proposed by ENTSO-E & EU DSO Entity, states:

*This compensation mechanism may encompass the reimbursement of **specific, verifiable additional costs directly associated with the service activation.***

Article 55A of the EBGL, proposed by ACER through the NCDR, states:

*"3. The financial compensation pursuant to paragraph 2 shall:*

a. *encompass the reimbursement of **specific, verifiable additional costs directly associated with the demand response activation** not already covered by the financial transfer pursuant to paragraph 1; and*

b. *include the **costs incurred by the supplier**."*

The suggestion in the Consultation to use a proxy for the retail price as a possible option is fundamentally flawed, given these parameters. The retail price in the SEM is made up of many charges, levies, tariffs, etc. as well as a supplier margin – none of which are incurred in the event of a non-delivery of energy. It is essential that only the costs incurred by the supplier as a direct result of the activation are included.

Therefore, VIOTAS contends that only the wholesale price (using the Day Ahead Price) should be used to calculate the supplier compensation price.

It is also important that the benefits of demand response are taken into account when calculating this charge, in accordance with Article 17(4) of the Directive, Article 55a(4) and (5) of the draft EBGL revision, and Article 22(b) of the NCDR. Such benefits include the lower wholesale prices as a result of DR activations, the lower network tariffs (especially due to units with on-site generation), lower system operation costs (especially due to units with on-site generation), and many more. While VIOTAS understands the complicated nature of doing so, the SEM Committee could use a proxy value for these benefits based on historic data and apply this on a per MWh basis to the PCOMP, reducing it by the appropriate value.

In conclusion, the relevant provisions of EU law, both in draft and in force, are prescriptive in nature as to the costs that may be included in the compensation price. These do not include costs that have not been incurred as a result of the non-delivery of energy. Therefore, VIOTAS contends that only the DAM price should be included as the starting point for the PCOMP, which should also be adjusted for the net benefits brought by DR on a per MWh basis.

**Q6:**

**(A) 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.**

VIOTAS does not believe that the Revised Phase 1 Solution would have the correct incentive effect on long-run DSUs.

Under this solution, in the event that the supplier compensation payment is greater than the energy payment received by the DSU, it would disincentivise long-run DSUs from participating in the DSU. This is because they would be paying out more in supplier compensation payments than they would be receiving in energy payments. In relative terms their earnings from DSU are low, so a loss every hour of running would quickly diminish or even out-weigh their capacity payment. This could have several negative results:

- It would almost certainly mean that long-run DSU operators would stop participating in DSUs.
- Having left the market for DSUs, some of these operators may no longer have a financial incentive to keep operating their onsite generation and so end its operation. This would lead to reduced capacity on the electrical system.
- For those who choose not to stop running their onsite generation, there would be two negative outcomes:

- They would not be incentivised to be operating at times of system stress, meaning a dangerous reduction in capacity at those times; and
- They would no longer be available to be curtailed at times of high wind penetration, leading to more curtailment of wind.

**(B) Would [a supplier compensation payment] impose reasonable costs on end consumers? Please explain your view.**

It is important to note that the need for compliance with the EU Law Provisions is not limited to actions which impose "*reasonable costs*" (a term that is not clearly defined). Nonetheless, as a general matter, the costs associated with granting DSUs energy payments are indeed reasonable. The impact assessment carried out by the TSO was during the high prices of 2022, which were expected to fall significantly and have done so. This was noted in the Final Recommendation Report of Mod_02_23, where the costs were deemed reasonable.

As such, the cost reduction measures in the Consultation are unnecessary, and have no bearing on the need for compliance with the EU Law Provisions.

**Q7:**

**(A) 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?**

No, this would be a significant reversal of the progress made in integrating demand response into the market. The EU has been pushing for a number of years for any Member State with such an arrangement in place to remove this requirement. Ireland should not be considering taking this step backwards. Specifically, it would be inconsistent with Article 17.3(a) of the Directive.

**(B) Or by ex-post analysis of demand reduction dispatch decisions? Please explain your views.**

This is more appropriate, assuming it describes Model 2 outlined in the Consultation.

**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.**

No, VIOTAS contests many of the statements made regarding the description and analysis of so-called "*Long Run DSUs*". As expressed in the main body of this response, the persistent use of the term "*long run DSU*" is concerning, as the SEM Committee appears to be using it to draw distinctions between units that do not exist.

The growing narrative that delineates between 'modes of participation' of units in the SEM is worrying, and fundamentally incorrect. All units, including GUs and DSUs operate under the conditions and parameters set out by the Grid Code and TSC. These parameters, largely the same for both GUs and DSUs, provide a framework for units to create specific values that distinguish them in the merit order. Terminology such as Base Load and Peaking Plants can be used as easy parlance when discussing the placement of units in this merit order as a result of the range of values they submit, but at no point, in either the Grid Code or the TSC, are these terms defined. Nor, in any documentation, is it specified that the values submitted under this framework could lead to differential treatment within the market. Similarly, the 'modes of participation' such as '*long run*' are simply a result of the market scheduler ordering units according to their technical and price offers. Units with low price offering will be called upon by the TSO for longer durations than those with higher costs. This logic stands for both GUs and DSUs and is a fundamental principle in our market.

**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.**

The inclusion of non-energy charges that have not been incurred by suppliers as a result of demand response activations is contrary to the provisions of EU law discussed above. Including capacity charges would be a major disincentive to explicit flexibility and therefore contradictory to other policy measures.

The models outlined in Section 4.1 are out of scope of DSU energy payments, and VIOTAS does not see value in answering.

**Q10:**

**(A) Do you consider that some form of baselining is needed?**

This question is misleading, as it suggests there is no form of baselining in place currently. DSU dispatches are currently baselined as per the methodology outlined in the Grid Code. While VIOTAS recognises the identification by EY in their report on the capacity market of the need for refinement of this methodology, it is disingenuous to imply that there is currently no methodology in place.

**(B) Would appropriate supplier compensation payment arrangements affect this?**

The supplier compensation has no bearing on the requirement for refinements of the baselining methodology.

**(C) 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 supplier compensation mechanism and DSU baselining have no relationship with one another. DSU baselining is a complex issue and should be discussed bilaterally with industry and consulted upon in its own right.

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

Sub-metering is an increasingly important measure that allows previously inaccessible loads to participate in the market and become flexible. It enables sites with multiple processes / load resources to be clearly attributable in a demand response activation, helping with measurement, and ultimately settlement – including in perimeter correction. Accordingly, it is being encouraged strongly by European Institutions, not least in the NCDR. The SEM Committee should work with market participants to adopt measures that enable the full use of sub-metering.

While it should not be mandatory but rather left to the discretion of the site and aggregator, it should be facilitated without delay to allow for easier perimeter correction when the SEM Committee move to implement such correction.

**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.**

VIOTAS agree with this change. Furthermore, this SCADA data should be used in place of the majority of EDIL declarations.

**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.**

AGUs and DSUs are fundamentally different participation methodologies. DSUs allow final consumers to offer their flexible demand into the market, either directly or through an aggregator. Such flexibility can be achieved through various forms, including on-site generation, as well as demand reduction. A key characteristic of a DSU is that it does not intend to inject electricity into the system (although there is scope for this under EU law), but rather to reduce its withdrawal by these means. All current DSUs operate on this premise.

AGUs, on the other hand, are currently not implemented in ROI. If introduced, it would be implicit that they would inject into the system and be paid accordingly. The difficulty of adopting this participation methodology for demand response is that measuring a site's response as its injection (without assessing its demand reduction) would render nearly every DSU dispatch as null.

Furthermore, additional requirements on monitoring, testing and communication would create a significant burden preventing the existing participant from providing valuable services to the TSO. Considering that a DSU legislation is not complete, and the type of unit is not fully implemented in the TSO's systems after more than a decade of successful operation of the technology, a requirement to force end-customers to provide demand management services via AGU would be disadvantageous and against the spirit and wording of the Clean Energy Package.

**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 fails to mention the historic payment of energy payments to DSUs, which have been entitled to such payments since 1 January 2020. The recent High Court judgment in *GR Wind Farms 1 Limited v Commission for Regulation of Utilities* [2023] IEHC 620 has confirmed the obligations placed on the SEMC under the provisions of the Regulation.

As such, we ask that the SEM Committee begin to engage with the industry as to how these historic payments will be made.

**Q15:**

**(A) What are you views regarding negative demand response?**

Assuming by "negative demand response" the SEM Committee is referring to negative demand reduction - Section 3.6 of the Consultation Paper sets out the practices of some DSUs in a way that, to a reader that may not understand the commonality of these practices across the industry, would make it seem that these market rules are unique to DSUs. The submission of negative decremental bid prices, where cost reflective as mandated by BCOP, and the concept of a DSU being paid to not reduce demand should be seen as no less of a valid market outcome than a generator being paid not to generate, which they often do for various reasons; both are perfectly rational market outcomes in certain scenarios. As such, any change in market rules regarding decremental bids should be applied to all units.

**(B) Do you consider the supplier compensation payment arrangement will work for negative demand response?**

The supplier compensation should have the ability to flow from the supplier to the service provider in the event of negative demand response – as they will benefit from the consumer's increased demand, assuming the supplier bills the consumer for this demand (which is expected). Any margin made by the supplier should be transferred to the service provider.

**(C) Do you think there is any potential for perverse outcomes and undue discrimination between customers? Please explain your view.**

No, there are no perverse outcomes from market participants performing actions as dictated by the market rules in place for all units.

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

The shutdown cost for a DSU is governed by the Bidding Code of Practice. All market participants are required to comply with this. There is no differential treatment of market participants based on their technology type. Any additional requirements would stifle the current operation of aggregated units and prevent growth of demand response (which is a goal set by the Government to the TSO and DSO).

From the point of view of aggregators, the composition of a DSU changes in real-time. Additionally, multiple IDS can be activated to provide response, with varying and variable response during the demand response event. So called "portfolio effect" allows the aggregators to provide the required response. Due to the fluid nature of a DSU's response, the shutdown costs could change every minute.

At the moment, the way to submit shutdown cost is purely manual, not user friendly and prone to delays caused by the mandatory use of outdated and unsecure internet browser. Even if there was a change to assessing and submitting shutdown cost more frequently that today (when a real change of shutdown cost is identified and documented), there is no technical capability on the market operator's side to receive such information.

A conventional powerplant does not receive different startup cost, if they are instructed to sync at the minimum generation value, or when they receive instruction to deliver maximum generation. A fair and transparent treatment of technology types of all market participants should be sustained.

When considering cost calculations for an aggregated unit, an aggregator must fairly treat their customers, and they must account for startup and shut down costs of all IDS. Only in case of a DSU with single IDS, there is no possibility to forecast which IDS will be instructed to provide the required response.

**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.**

The calculation of decremental bid prices is determined by the TSC for all units. Many unit types regularly submit decremental bids, such as older baseload generation (which prefer to remain at a constant generation load), as well as Waste to Energy (WtE) plants (which operate regardless of market participation or system conditions).

The rules that apply to all units are deemed reasonable by VIOTAS and require no change.

**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 Grid Code states that DSUs are "*an Individual Demand Site or Aggregated Demand Site with a Demand Side Unit MW Capacity of at least 4 MW. The Demand Side Unit shall be subject to Central Dispatch.*"

This does not include the requirement for DSUs to declare an availability of 4 MW or above on a regular basis.

**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.**

VIOTAS does not accept this interpretation of its binding obligations regarding availability declarations under the Grid Code.

An important contributing factor to this issue is the fundamental system limitation with the EDIL system, which can only accept integer values for availability declarations. This flawed user interface restricts market Participants' ability to provide good quality declarations of real-time availability. Via DRAI, VIOTAS and others have raised this concern for multiple years, and explained its high materiality, especially for small units. While the TSOs have stated that they are exploring changes to the EDIL system to consider enabling the submission of declarations to a higher degree of accuracy, VIOTAS is not aware that this has been prioritised for delivery in any of the TSOs' work plans or roadmaps.

In certain circumstances, applying an overly simplified rounding logic to determine an appropriate declaration would result in this TSO system flaw unfairly manifesting material impact on the market participation of small units. Nowhere in the Grid Code is such a specific requirement to round declarations to the nearest integer specified. Contrary to this, it is important to note that throughout many aspects of the Grid Code, an applicable tolerance of at least 1 MW is enshrined.

VIOTAS is satisfied that it is meeting its binding Grid Code obligations to use *reasonable endeavours* to ensure our EDIL availability declarations reflect what each DSU could achieve at the relevant time, within applicable tolerances and that it is acting in accordance with *good industry practice*.

**General Comment Regarding Consultation Questions**

VIOTAS strongly feels many of these questions are considerably out of scope of DSU energy payments. We do not feel it is appropriate that a significant portion of the Consultation questions address minor points such as rounding and availability declarations, when a matter of greater importance is being delayed – significantly impacting the DSU industry.