Demand Side Units: A Revised Phase 1 Solution for Energy Payments and Other Issues

Consultation Paper

SEM-24-046

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EXECUTIVE SUMMARY

The SEM Committee considers that demand response, both implicit and explicit, will become increasingly important in meeting decarbonisation targets with intermittent generation from renewable sources. This consultation paper considers market rules and incentives that will allow Demand Side Units (DSUs), a form of explicit demand response, to complete on an equal footing with other technologies, and that will reward DSUs that deliver value to the system to the ultimate benefit of end customers.

The paper reviews the underlying rationale for making energy payments to DSUs. It is recognised that, without appropriate arrangements, the supplier of a demand site that effects a demand reduction will inadvertently benefit from the avoided SEM wholesale market purchase costs, which tend to be at their highest when demand reduction is called and will often outweigh the loss in supplier charges on the customer. At the same time, the benefit to the customer and DSU is limited to the savings in supplier charges to the customer, rather than the full wholesale market price. This sharing of the benefits of demand reduction with the supplier creates a "missing money" problem for the DSU, whereby any DSU that is close to the margin, i.e. whose costs are close to the wholesale price, may operate at a short run loss. Consequently, the incentives for a DSU may be to minimise rather than maximise availability at times when demand reduction is most needed.

In 2022, the SEM Committee consulted on providing energy payments for DSUs (SEM-22-036). The consultation resulted in an enduring "Phase 2" solution, in which the supplier is required to buy the "non-consumed energy" that the DSU sells back to the system as demand reduction.

It is understood that the systems changes required to identify the particular supplier that benefits from a given demand reduction are difficult to implement. Hence, the SEM Committee also decided that, subject to impact assessment, a temporary "Phase 1" solution should be implemented until the enduring solution was ready. Under this solution the energy payment to the DSU would be funded not by the particular supplier but by all end customers through the Imperfections Charge levied on all suppliers.

The subsequent impact assessment estimated that the Phase 1 solution would lead to an increase in the Imperfections Charge of around €56 million per year. By far the greater proportion of this cost, in the region of €52 million, would result from payments to "long-run" DSUs, which typically comprise low-cost, on-site generation that runs most, if not all, of the time. This cost would be borne ultimately by end customers and would be incurred without bringing about any significant change in behaviour or additional demand response or other benefits to the system. The SEM Committee considers that responses to the 2022 consultation did not reflect the significance of these long-run DSUs. In addition, since the decision, ACER has published a Framework Guideline on Demand Response, while a Network Code on Demand Response is currently being developed. These provide considerable additional detail on putting demand response on an equal footing with other resources, such as generation. Hence, the SEM Committee considers it appropriate to consult further on the Phase 1 solution.

This consultation identifies a potential alternative Phase 2 solution in which the supplier, rather than being compensated for the non-consumed energy by its customer, would be compensated directly by the DSU through a 'supplier compensation payment' (which could be based on a proxy for the average retail energy price).

Applying a similar approach to Phase 1, the DSU would pay the supplier compensation payment, not to the particular supplier, but to the Imperfections Charge fund. In this revised Phase 1 solution, while the DSU and customer may benefit in the first instance from both the savings in the supplier’s charges to the customer, as well as energy payments from the SEM, these savings will be passed on to the Imperfections Charge fund through the supplier compensation payment. Consequently, as shown in the Figure below and described in the following paragraphs, the DSU and customer benefits from energy payments, but not from both energy payments and the savings in supplier charges.

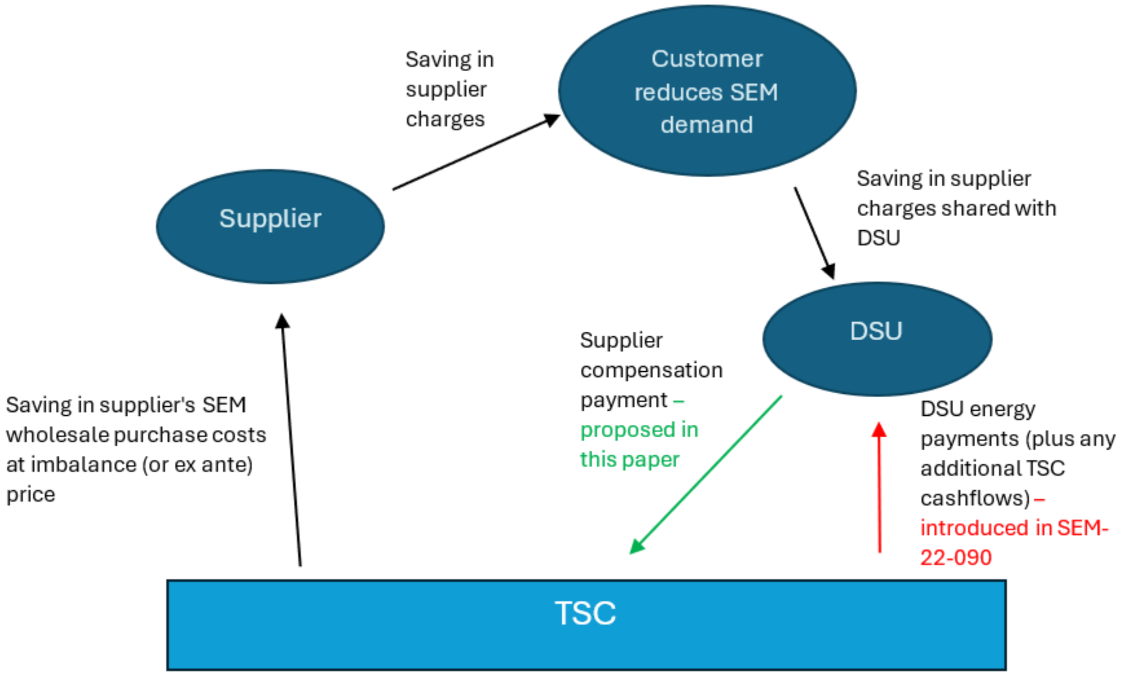

Figure: Revised Phase 1 Solution Demand Reduction Cashflows

Specifically, in the revised Phase 1 solution:

- *DSUs*: Energy payments (at the balancing market or ex ante market price) address the missing money problem for high-cost DSUs that provide demand reduction at times of high wholesale prices. However, long-run DSUs should not expect to receive additional revenue, which is appropriate given that these DSUs do not have a missing money problem, and their costs are fully compensated in the savings in supplier's charges.
- *Suppliers*: Suppliers continue to benefit from demand reductions when wholesale prices are high. With long-run DSUs, the supplier will incur lower SEM wholesale market costs but will receive less in supplier charges from the customer. All suppliers will have to pay slightly increased Imperfections Charges.
- *Customers*: The Imperfections Charge, which is borne by all end customers via their suppliers, funds the cost of DSU energy payments (at the balancing market or ex ante market price) but this cost is offset by supplier compensation payments (which could be based on a proxy for the average retail energy price) into the Imperfections Charge fund.

The paper also considers a number of other associated issues, including:

- *Baselining and Metering*: Currently, demand reduction is not measured under the Trading and Settlement Code and, instead, any demand reduction which is dispatched is deemed to be delivered. Effectively, this exempts DSUs from balance responsibility. Options under consideration include:

  (i) baselining demand sites, such that data from existing metering can be compared with baselined quantities, and delivered demand reduction calculated as the difference between the two;

  (ii) sub-metering, whereby sub-meters are used to measure the demand reduction from controllable processes and/or generation from on-site generators, rather than just the net demand for the site as whole; and

  (iii) using data currently used for performance monitoring under the Grid Code.

- *Availability Declarations*: It is understood that there have been issues concerning the availability declarations submitted in respect of DSUs. The current Grid Code obligations are discussed, and it is suggested that these require declarations of availability of at least 4 MW from DSUs and require declarations of availability to be rounded down to the nearest MW. It is recognised, however, that the Network Code on Demand Response may require TSOs to permit declarations to be made to the nearest 0.1 MW.

- *Bid Compliance*: The SEM Committee is aware of a number of issues relating to bid prices for DSUs. In particular, it is understood that:

  (a) in some instances, shutdown costs for Individual Demand Sites (IDSs) have been aggregated into a single shutdown cost for the DSU, which then may be payable even if only small demand reductions, which do not involve demand reductions at all sites, are called; and

  (b) some DSUs have been declaring decremental prices which are very negative, such that the DSU must be paid in order to not reduce demand.

- *Aggregated Generator Units*: The Trading and Settlement Code has provisions for the aggregation of small-scale generation to form Aggregated Generator Units (AGUs). In principle, on-site generation that currently participates in the SEM as part of a DSU could, instead, participate as part of an AGU. AGUs would ensure that such generation were more efficiently incentivised and receive the same payments as other Generator Units.

- *Dynamic Tariffs*: Dynamic tariffs are required under the Clean Energy Package and are expressly intended to encourage customers to be more responsive to real-time prices. These obligations may not be relevant for the duration of the revised Phase 1 DSU solution, although it is possible that suppliers and DSU customers could have negotiated dynamic tariffs. If the dynamic nature of tariffs is not reflected in supplier compensation payments then incentives for demand reduction could exceed the efficient level.

The SEM Committee welcomes views from all stakeholders on any aspect of the analysis and discussion, and on any related issues, noting that the issues do not necessarily have to be addressed in a single package of measures, but could be addressed one-by-one, as appropriate.

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Glossary of Terms and Abbreviations

Abbreviation or Term	Definition or Meaning
ACER	Agency for the Cooperation of Energy Regulators
AGU	Aggregated Generator Unit
BCOP	Bidding Code of Practice
COD	Commercial Offer Data
CRU	Commission for Regulation of Utilities
DSU	Demand Side Unit
EDIL	Electronic Dispatch Instruction Logger
ENTSO-E	European Network of Transmission System Operators (Electricity)
EU / EC	European Union / European Commission
FGDR / NCDR	Framework Guideline / Network Code for Demand Response
IDS	Individual Demand Site
MW / MWh	Megawatt / Megawatt-hour
PIMB / QD / QM / FPN	Imbalance Price / Dispatch Quantity / Metered Quantity / Final Physical Notification.
PCOMP / PSUPP	Supplier Compensation Price / Supplier Purchase Price.
PCM	(Ofgem) Price Cap Methodology
RAs	Regulatory Authorities
RO	Reliability Option
SCADA	Supervisory Control and Data Acquisition
SEM	Single Electricity Market
SEMO	Single Electricity Market Operator
TSC	Trading and Settlement Code
TSO / DSO	Transmission / Distribution System Operator
TSSU	Trading Site Supplier Unit

1. Introduction

This paper is a follow-up consultation on the Phase 1 solution for energy payments under the Trading and Settlement Code (TSC) to Demand Side Units (DSUs). An impact assessment undertaken by the TSOs/SEMO, following the consultation in 2022 and the raising of a TSC Modification Proposal in 2023, highlighted a particular mode of participation in SEM exhibited by some DSUs, which typically comprise low-cost on-site generation, and showed that a significant cost will result from energy payments to these "long-run" DSUs. Responses to the 2022 consultation and hence the subsequent decision did not reflect the significance of this type of DSU, while the impact assessment has estimated that the proposed Modification would result in a cost to end customers of over €50 million per year in respect of such DSUs, without bringing forward significant change in behaviour or additional demand response or otherwise delivering benefit to the system. Moreover, since the decision, ACER has published a Framework Guideline on Demand Response, while a Network Code on Demand Response is being developed. Accordingly, the SEM Committee considers it prudent to revisit the issues and seek views on more appropriate arrangements to incentive enhanced DSU operation.

The structure of the remainder of the paper is as follows:

Section 2: gives background to DSUs in the SEM, including previous consultations and decisions. It also outlines current and forthcoming EU legislative requirements;

Section 3: discusses the benefits and rewards for DSUs in the energy market, and options for a revised Phase 1 solution;

Section 4: discusses other aspects of the revised Phase 1 solution, including baselining, metering, availability declarations; and bid compliance;

Section 5: summarises and outlines how to respond to the consultation.

There are a number of appendices:

Appendix A: lists consultation questions;

Appendix B: explains demand reduction cashflows for the various models, and for a revised Phase 1 solution;

Appendix C: provides numerical examples under the various models and under the revised Phase 1 solution;

Appendix D: outlines the approach taken in a number of other electricity markets to setting a supplier compensation price, or its equivalent;

Appendix E: lists relevant Grid Code provisions; and

Appendix F: lists references.

2. Background

2.1. Initial I-SEM Design and State Aid Approval

In the initial design of the Capacity Market for the current Single Electricity Market, introduced in 2018, Demand Side Units (DSUs) were exempted from the liability to pay Difference Charges when demand reduction is delivered on the ground that they do not receive energy payments[1]. State Aid approval[2] was granted by the European Commission (EC) based on a commitment by the RAs to end this exemption. The EC considered also that applying Difference Charges to DSUs that do not receive energy payments would place them at a disadvantage compared to other capacity providers, and that the situation that DSUs cannot access energy payments may need to be remedied. It further noted that it could not be excluded that DSUs benefit from energy payments indirectly, either via the consumers whose demand reductions they aggregate or via the supplier to whom they are "affiliated", and hence requested that SEM strive to enable DSU treatment equivalent to that of other capacity providers.

2.2. Previous SEM Committee Consultations

In 2019, a SEM Committee decision[3] and subsequent Trading and Settlement Code (TSC) Modification provided an “interim solution”, enabling energy payments to be made to DSUs only during "Reliability Option events” (RO events), i.e. when market prices are above the RO Strike Price, and Difference Charges are payable. As an interim measure, the costs of these energy payments were to be paid by all suppliers on some equitable basis, which, in the resulting TSC Modification[4], was defined to be through the Imperfections Charge. Given that the costs would be incurred only

[1] Note that "energy payments" is not a term that is used in the Trading and Settlement Code or related documents. However, it generally refers to the payment for megawatt-hours delivered or sold in the balancing market (at the Imbalance Price) or ex ante markets (at the relevant Day-ahead Price or Intraday Price)

[2] State aid No. SA.44464 (2017/N) – Ireland – Irish Capacity Mechanism, C(2017) 7789 final, European Commission, 24 November 2017; SA.44465 (2017/N) – United Kingdom – Northern Irish Capacity Mechanism, C(2017) 7794 final, European Commission, 24 November 2017.

[3] Capacity Remuneration Mechanism DSU Compliance with State Aid. Decision Paper", SEM-19-029, July 2019.

[4] "Final Recommendation Report: Mod_17_19”.

during relatively infrequent RO events, the impact on the Imperfections Charge would be limited[5].

The SEM Committee issued a further decision[6], in November 2022, on a phased approach towards an enduring solution, intended to provide DSU energy payments at all times, and not just when market prices are above the RO Strike Price. In particular, the SEM Committee decided to proceed with a temporary "Phase 1" solution in which the arrangement, whereby a Trading Site Supplier Unit is charged for the demand that corresponds with the demand reduction for which each DSU is paid, is ended. 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, the costs of which would have to be funded by all end customers via the Imperfections Charge on all suppliers. The decision was subject to impact assessment and, as part of the preparation for raising a TSC Modification Proposal for the Phase 1 solution, the TSOs and SEMO were asked to undertake an impact assessment on the continued use of the Imperfections Charge to fund the expanded DSU energy payments.

The impact assessment estimated that the Phase 1 solution would lead to an increase in the Imperfections Charge of around €56 million per year[7]. It also revealed that by far the greater proportion of this cost, in the region of €52 million, would result from payments to "long-run" DSUs. These are DSUs that typically comprise low incremental cost, on-site generation which is in-merit, and hence running most if not all of the time. Typically, such generators are combined heat and power generators installed to meet an industrial requirement for heat, as well to reduce the cost of electricity purchases from the SEM. Responses to the 2022

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[5] Note that where the DSU has not traded ex ante, the DSU energy payment takes the form of an Imbalance Component Payment, which contributes directly to Imperfections Charges. Where the DSU trades ex ante, the energy payment to the DSU takes the form of a payment from the ex ante market. However, the DSU ex ante trade will displace an ex ante trade by some other TSC Party, and hence will result in an Imbalance Component Payment, or the reduction in an Imbalance Component Charge, to that other TSC Party. Hence the impact on Imperfections Charges is the same, regardless of whether the DSU has traded ex ante or whether it is paid at the Imbalance Price.

[6] "Enduring Solution to Enable Energy Payments in the Balancing Market for DSUs. Decision Paper", SEM-22-090, 25 November 2022.

[7] "Constraints Costs (Imperfections Charges) October 2023 – September 2024 and Reforecast Report October 2021 – September 2022. Consultation Paper", SEM-23-049, 30 June 2023, Section 3.2.2,

consultation did not reflect the significance of these long-run DSUs, and hence the SEM Committee's decision was made on the basis that DSUs would be reducing demand only intermittently, at times of high prices.

2.3. Clean Energy Package and ACER Framework Guideline

Two elements of the EU's Clean Energy Package are the Electricity Regulation[8] and the Electricity Directive[9]. As noted in the 2022 consultation, Article 17(1) of the Electricity Directive requires Member states to "*allow and foster participation of demand response through aggregation*", and to "*allow final customers, including those offering demand response through aggregation, to participate alongside producers in a non-discriminatory manner in all electricity markets*", while Article 6(1)(a) of the Electricity Regulation requires balancing markets to "*ensure effective non-discrimination between market participants taking account of the different technical needs of the electricity system and the different technical capabilities of generation sources, energy storage and demand response*".

The Electricity Directive also defines, in Article 2, demand response as meaning "*the change of electricity load by final customers from their normal or current consumption patterns in response to market signals*", while Article 17 states that the regulatory framework must include "*an obligation on market participants engaged in aggregation to be financially responsible for the imbalances that they cause in the electricity system*", 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*", and that "*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 3 of the Regulation requires electricity markets to be operated in accordance with a number of principles, including "*market rules shall deliver appropriate investment*

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8 "Regulation (EU) 2019/943 of the European Parliament and of the Council on the internal market for electricity", 5 June 2019.

9 "Directive (EU) 2019/944 of the European Parliament and of the Council on common rules for the internal market for electricity and amending Directive 2012/27/EU", 5 June 2019

incentives for generation, in particular for long-term investments in a decarbonised and sustainable electricity system, energy storage, energy efficiency and demand response to meet market needs, and shall facilitate fair competition thus ensuring security of supply" and "*safe and sustainable generation, energy storage and demand response shall participate on equal footing in the market, under the requirements provided for in the Union law*".

In December 2022, ACER submitted to the European Commission a draft framework guideline on demand response (FGDR), setting out principles for the development of harmonised rules for demand response. The FGDR states that rules shall specify the payer of compensation, with the compensation being paid to the supplier of the final customer. It states that the rules, which shall ensure that compensation is not creating a barrier to aggregation, will comply with Article 17 of the Directive. Then, in March 2023, the EC invited ENTSOE and DSO Entity to submit to ACER a proposal for a Network Code on Demand Response (NCDR), in line with the framework guideline. In September 2023, ENTSOE and DSO Entity published a draft for consultation, and submitted their proposal in May 2024. Article 22a of the proposed NCDR states that Member States may require suppliers or service providers or active customers to pay financial compensation, using a specific formula, a specified amount, or as agreed between the parties.

In December 2023, ACER published a report into barriers to demand response and other distributed energy resources[10] in EU Member States. The report cites a number of issues, including the lack of a proper legal framework to allow market access and the lack of incentives to provide flexibility, including the lack of smart metering, in nearly half of the Member States, and an absence of price signals to end users.

[10] "Demand response and other distributed energy resources: what barriers are holding them back?", 2023 Market Monitoring Report, ACER, 19 December 2023.

3. Energy Payments for Demand Response

3.1. Demand Response

As reflected in the definition of demand response in the Electricity Directive, demand response is the change in load of final customers from their normal or current consumption patterns in response to market signals. A customer will derive a certain utility from the consumption of electricity, and if the electricity price exceeds the utility of consumption, then a rational demand responsive customer will choose not to consume. This demand response may be implicit, in that the customers choose not to consume in response to prices being charged by the supplier. Alternatively, demand response may be explicit, whereby customers declare the prices at which they prefer not to consume, and the system operator can instruct them not to consume, in a manner similar to a generator being instructed to generate.

DSUs are intended as a mechanism of facilitating explicit demand response in the SEM, enabling demand reduction to be offered and accepted in a similar manner to generation being offered and accepted from a Generator Unit. Explicit demand response provides value over and above implicit demand response to the extent that it provides the TSOs with more certainty of response, whereby the TSOs instruct the demand response which is then under an obligation to respond. In contrast, implicit demand response relies on demand reacting to price signals, without any obligation and hence certainty for the TSO that it will do so. However, a widely recognised problem with explicit demand response is that it introduces the "baselining" problem, i.e. in quantifying the value of explicit demand response to the system, some measure is required of what demand would have been had the explicit demand reduction not been instructed.

In principle, customers could choose to register DSUs themselves on their own behalf. However, a common arrangement is that an "aggregator" will form a DSU from the demand response available from a number of customer sites, known as Individual Demand Sites (IDSs), in order to create a DSU providing amounts of demand response that are useful to the system operator. It is then a private matter between the aggregator and the individual customers as to how to share the benefits of not consuming, i.e. the savings in purchase costs over and above the cost of not consuming plus any premium that might be received for explicit demand response, plus other revenues such as capacity payments and system services revenues.

3.2. "Long-run" Demand Response

Rather than by foregoing consumption, demand response may also be achieved by a customer having its own, or contracting with, on-site generation. In these cases, the utility of consumption is not usually a consideration. Instead, the customer will choose to generate, or purchase, electricity from the on-site generator when the cost of doing so is less than the cost of purchase from its supplier. It is not uncommon that the on-site generation is a combined heat and power facility, which both satisfies a heat load, as well as producing electricity at relatively low incremental cost. Such generation will typically operate baseload, and the benefits of not consuming are just the benefits of not consuming from the SEM, i.e. the saving in purchase costs through the SEM over and above the cost of operating the on-site generation.

Where the customer purchases the on-site generation from another party then, as with other demand response, the benefits are shared between the parties on the basis of the private agreement between them.

3.3. Short-run DSU 'Missing Money' Problem

The term "missing money" is normally used in the context of capacity markets, to describe the situation where wholesale market prices do not reach levels high enough to reflect the costs of an efficient level of generation capacity. With demand response, a different potential missing money problem exists to the extent that, at any given time, the price charged by the supplier to the customer may not reflect the price in the wholesale market. Typically, this might arise where a supplier is supplying the customer on a fixed price contract such that the price charged to the customer is below the wholesale price at times of wholesale price peaks, even taking into account additional charges and the supplier's margin, etc. For example, the supplier might be charging the customer a flat rate of €150/MWh, which may be representative of the average cost of supply, but which may be far less than wholesale prices, whether Imbalance Price or ex ante price, when these hit a peak of, say, €400/MWh. In effect, at these times, the supplier is subsidising the price of electricity to the customer, albeit in exchange for higher margin when wholesale prices are low. As a result, the customer will be incentivised to make consumption decisions that, while efficient for the customer, are not efficient from the perspective of the system. Put another way, the value of any demand reduction is split between the customer and the supplier, with the supplier receiving an inadvertent gain through not supplying the customer at a loss, and the reduced benefit to the customer may be insufficient to reward efficient decisions.

It is this problem which is cited by the December 2023 ACER market monitoring report as being one of the barriers to demand response (as well as other distributed energy resources). While this problem certainly exists for implicit demand response, explicit demand response, such as provided by DSUs, provides a means to expose the customer or aggregator to efficient wholesale prices, when the wholesale price is greater than the price being charged by the supplier.

That said, the wholesale price being greater than the price being charged by the supplier does not automatically mean there is missing money. Specifically, if the incremental price of the demand reduction, or more typically the incremental cost of on-site generation[11], is less than the price being charged by the supplier then the demand reduction will be in merit, and it will already make economic sense for the customer to run the on-site generation at all times. The price charged by the supplier may at times be less than the cost of purchase from the SEM, but will be greater at other times: provided that the price charged by the supplier is reflective of the wholesale price on average, a long-run DSU will earn the same rent by offsetting supplier charges as being exposed to the wholesale price.

However, while long-run DSUs may not be affected, the missing money may have a detrimental effect on “short-run” DSUs. Specifically, when a DSU effects a demand reduction at times of high wholesale prices, a supplier which is supplying at that moment, at below cost, will make a saving equal to the amount by which the customer charges fall short of the wholesale price (plus network charges, etc.). In essence, the DSU's missing money arises because the costs savings are shared, without agreement, with the supplier. Consequently, where demand reduction is achieved either by foregoing consumption or by using high-cost standby generation,

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[11] If the utility of electricity consumption is less than the price being charged by the supplier, it would not be rational for the customer to enter into a supply contract in the first place.

then it is possible that the costs are low enough to be dispatched but higher than the savings in purchase costs from the supplier. In such circumstances, the DSU will be dispatched but will run at a loss. If DSUs are faced with this situation then their availability may be reduced, potentially forcing the TSOs to take more expensive balancing actions.

3.4. Models for Compensating Demand Response

Implicit demand response is compensated purely by the reduction in the costs of purchase, via the supplier, from the SEM. This reduction in purchase costs compensates the customer either for the loss in utility of consumption of electricity from the SEM, e.g. the value of lost production for a manufacturing customer, or for the cost of operating, or purchasing from, on-site generation. If the supplier does not reflect the full wholesale price in the price it charges the customer then the customer or the on-site generator (if different) may not make decisions that are efficient for the system as a whole, as part of the benefit of any demand reduction will be shared with the supplier, which will enjoy a reduction in the costs of purchasing from the SEM that exceeds the reduction in revenues from the customer.

For explicit demand response, three potential compensation models are considered below. These are presented, not as proposals for the SEM, but to illustrate options from first principles, and develop the logic for a revised Phase 1 solution, as discussed in Section 3.5. The models are also described in more detail, and shown diagrammatically in Appendix B, and numerical examples are provided in Appendix C.

Model 1: No DSU Energy Payments

In this model:

- the supplier sees a reduction in purchase costs from the SEM at the Imbalance Price, PIMB;
- the customer sees a reduction in purchase costs from the supplier at the purchase price, PSUPP;
- the DSU (which, in principle, could be registered by the customer or could be registered by an aggregator) receives any SEM revenues *over and above* PIMB or the ex ante price;

- the DSU may also receive PIMB or the ex ante revenues (for any demand reduction sold in the ex ante market) but would be required also to buy the demand corresponding with the demand reduction; and
- the customer bears either:
  (a) the cost of lost production; or
  (b) the cost of generation by the on-site generator.

This is essentially the model that was implemented in the SEM at Go-Live in 2018. It was implemented by paying the DSU for energy at PIMB, or at the ex ante price for any proportion of the DSU output sold in the ex ante market, plus any other TSC cashflows over and above the energy payments, such as CPREMIUM and shutdown costs. However, in the SEM, the DSU is also required to register a 'Trading Site Supplier Unit' (TSSU) that must buy the quantity of energy that is sold back by the DSU as demand reduction, leaving only the additional TSC cashflows. From the perspective of the SEM, the SEM has a reduced revenue, priced at PIMB, from the supplier, but saves PIMB in reduced payments to some other generator or resource whose output is no longer required.

In this model, the DSU and customer derive a benefit equal to the reduction in purchase cost from the supplier plus any revenues from the TSC over and above PIMB. It suffers from the same problem as implicit demand response, in that the sharing of benefits, in the form of the inadvertent gain to the supplier, can result in DSUs being dispatched at a loss.

Model 2: DSU Energy Payments

In this model:

- the DSU receives PIMB or ex ante revenues, plus any additional TSC revenues;
- the supplier does not see a reduction in SEM purchase costs, because it is required to purchase the 'non-consumed' energy in addition to metered quantities, as if the demand reduction had not occurred;
- the supplier bills the customer for the ‘non-consumed’ energy, in addition to metered quantities, as if the demand reduction had not occurred;
- the DSU (which, as in Model 1 above, could be customer or a separate party) compensates either:

(a) the customer for the value of lost production; or

(b) the on-site generator for the cost of generation.

This is essentially the model proposed as a Phase 2 solution in SEM-22-090. From the perspective of the SEM, the DSU is paid at PIMB, replacing a payment also at PIMB to the generator whose output is no longer required.

Note that, unless the supplier is required to pay for the non-consumed energy, the demand reduction will be double counted, in that the supplier will benefit from a reduction in purchase costs and will not bill the customer for the non-consumed energy, as well as the DSU receiving energy revenues. The cost of this double counting is borne by all end customers in the SEM, via the Imperfections Charge on suppliers[12].

The SEM Committee understands that identifying the relevant supplier for each DSU, and implementing changes such that the suppliers can be charged for the non-consumed energy, will take a considerable time to implement. In SEM-19-029, the impact on end customers of double counting was reduced by limiting energy payments to only when Difference Charges are payable. The Phase 1 solution in SEM-22-090 extended the principle of paying energy payments to DSUs, albeit, as noted earlier, on the understanding that demand reduction would be intermittent, hence limiting the impact of double counting.

A further potential complication of this model is that affected suppliers need to charge their customers for the non-consumed energy. This is likely to require changes to contracts between suppliers and customers, and potentially could require changes to retail market rules, retail market systems, supplier codes of conduct, supplier licences and perhaps even legislation. In cases where the DSU and the customer are different parties, it is likely also that the requirement for the customer to pay the supplier for non-consumed energy will need to be reflected in the terms that are agreed between the customer and the DSU.

Model 3: DSU Energy Payments with Supplier Compensation

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[12] It is assumed that, in a competitive market, a cost, such as the Imperfections Charge, which is imposed on all suppliers, will be passed on by suppliers to their end customers.

A further model is similar to Model 2 above, except that, rather than the supplier having to bill the customer for the non-consumed energy, the DSU compensates the supplier through the TSC. Hence:

- the DSU receives PIMB or ex ante revenues, plus any additional TSC revenues;
- the supplier does not see a reduction in SEM purchase costs, because it is required to purchase the 'non-consumed' energy, in addition to metered quantities, as if the demand reduction had not occurred;
- the DSU (which, as in Model 1 above, could be the customer or a separate party) compensates either:
  (a) the customer for the value of lost production; or
  (b) the on-site generator for the cost of generation; and
- the DSU compensates the supplier for the non-consumed energy, at a “supplier compensation price", PCOMP.

This model is contemplated by the proposed NCDR[13], with compensation to the supplier being priced at "*a specific formula or a financial amount”*, or by *“bilateral agreements between the supplier and the service provider*".

Under this arrangement, the supplier does not benefit from an inadvertent gain, equal to the difference between the Imbalance Price and the price to the customer. Instead, the full value of the demand reduction is retained by the DSU, to be shared with the customer or the on-site generator, to cover the costs of effecting the demand reduction.

3.5. Revised Phase 1 Solution

In the absence of a solution for identifying the relevant suppliers to compensate, affected suppliers will see a reduced demand, as in Model 1. Hence, they will lose revenue from the customer but will also save SEM purchase costs, and so continue

[13] Article 22a(5) states, "*The calculation method of the financial transfer: (a) shall be developed and published by the competent regulatory authority; (b) shall be publicly consulted according to Article 13 (Public consultation for national terms and conditions); and (c) shall consist of either a specific formula or a financial amount.* ". Article 22a(7) states, " *National legislation or terms and conditions approved at national level may allow bilateral agreements between the supplier and the service provider to negotiate the financial conditions implied by such financial transfer mechanism.* ".

to receive the inadvertent gain. Without some other measure, the supplier's inadvertent gain continues to be missing money for the DSU.

One option might be a voluntary agreement between the supplier and the DSU, whereby the supplier would accept a correction for the non-consumed energy, compensated at a price representative of the lost customer revenues. However, there is no obvious reason why the supplier would voluntarily surrender its gain. Thus, a workaround solution would be required whereby supplier corrections for non-consumed energy would need to be identified and imposed through ex post analysis of demand reduction dispatch decisions. The SEM Committee would welcome any proposals as to how such a solution could be expedited. Either payments to DSUs could be funded through the Imperfections Charge in the first instance, with the costs recouped ex post from the benefitting suppliers, or payments to DSUs could be made ex post.

An alternative is that, while the supplier that benefits from the reduced consumption of its customer cannot be identified, the DSU still makes supplier compensation payments, but pays them to the Imperfections Charge fund, instead of to the particular supplier. Hence, while affected suppliers will be paid at PIMB for being long (or pay less at PIMB for being less short), funded by the Imperfections Charge, this cost will be offset by the supplier compensation payments. The DSU pays compensation to all suppliers via the Imperfections Charge fund, as all suppliers are financially impacted by demand reductions by dint of paying for DSU energy payments via the Imperfections Charge. Thus,

- the DSU will be paid PIMB or an ex ante price, but will pay back the supplier compensation price;
- all suppliers will pay for DSU energy payments via the Imperfections Charge;
- the affected supplier will receive reduced revenues from the customer, but will benefit by PIMB for its reduced SEM purchases; and
- the DSU will compensate:
  (a) the customer for the value of lost production; or
  (b) the on-site generator for the cost of generation.

From the perspective of the SEM, the DSU will be paid PIMB, replacing a payment to the generator at PIMB whose output is no longer required, as in Model 2. However, while there will be a loss in revenue from the supplier at PIMB, as in Model 1, this will be offset by a revenue from the DSU at PCOMP. Thus, when the PIMB is high, there will be a net cost to the SEM, representing the amount by which PIMB exceeds PCOMP. This net cost will be borne by end customers via the Imperfections Charge on suppliers. The supplier will enjoy an inadvertent gain equal to (PIMB - PSUPP), while the DSU will net (PIMB - PCOMP), which should correspond with the costs of effecting the demand reduction less the customer's savings made through the reduced costs of purchase from the supplier.

One concern that has arisen with the Phase 1 solution in SEM-22-090 is that the double counting of demand reduction, i.e. the making of energy payments to DSUs as well as the savings for suppliers, would become an unreasonable cost to impose on end customers, given the prevalence of long-run DSUs. The SEM Committee invites views on the extent to which the incorporation of the supplier compensation payment alleviates this problem. In particular, provided PCOMP is set appropriately, DSUs that are providing demand reduction at all times will pay at least as much to the Imperfections Charge fund in supplier compensation payments as they cost in payments at PIMB or ex ante prices. Only where DSUs provide demand reduction when prices are high but not when they are low will there be a net cost to the SEM, and then only until the enduring solution is able to correctly identify the supplier that is benefitting from the demand reduction. Meanwhile, provided PCOMP reflects the savings in the cost of purchasing from the supplier then the DSU missing money problem should be alleviated, and the distortion of incentives to DSUs minimised.

Options for determining PCOMP include:

- Directed Contract prices (baseload; mid-merit; peak; or some combination thereof) plus the Capacity Charge and the Imperfections Charge;
- 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; or
- some other methodology.

Other methodologies have been adopted in a variety of other electricity markets, in similar circumstances, and examples are described in Appendix D.

Baseload prices may be most appropriate for industrial demands, which do not follow the profile of overall system demand, and which are most likely to be types of demands that offer demand response. It is for consideration whether it would be appropriate to introduce an element of time-of-use pricing. Whatever the methodology adopted, it would seem appropriate that it be enshrined in a methodology statement, which would be subject to change control and, if appropriate, regulatory approval.

The SEM Committee also understands that the two broad modes of participation exhibited by DSUs, i.e. (i) those that provide demand reduction intermittently by controlling demand-consuming processes, or from high incremental cost standby generation, and (ii) long-run DSUs, providing constant demand reduction typically from low-cost on-site generation, are quite distinct. Indeed, it may be that consideration should be given to whether the definition of demand response, which refers to changes in load from normal or current consumption patterns in response to market signals, applies at all to long-run DSUs. As such, it may be possible to distinguish between these two modes of participation on the basis of the proportion of hours that they provide demand reduction, and so define categories and eligibility criteria to be used instead of, or in combination with, the compensation formula discussed above. Rather than paying a fixed supplier compensation price, it may be possible that long-run DSUs pay supplier compensation at the Imbalance Price, potentially plus the Capacity Charge, so that such long-run DSUs neither lose, nor benefit, significantly from differences between the supplier compensation payment and the average costs of purchasing from the SEM. That said, it may be non-trivial to retrospectively re-assign a DSU from one category to the other, with consequential changes in the settlement, in the event that an eligibility criterion is breached. Views on the practicality of such an approach, either alone or in combination with other approaches, would be welcome.

3.6. Negative Demand Reduction

A situation has arisen in SEM whereby DSUs can be used as a vehicle to offer dispatchable demand increases. This is achieved by declaring a FPN for the demand reduction together with a decremental bid to decrease the amount of demand reduction, i.e. to increase demand. In total, the transactions in a given hour would be:

(i) the DSU buys 1MWh, say, of demand through its TSSU;

(ii) the DSU sells 1MWh of demand reduction in the ex ante market, and declares an FPN of 1MW; and

(iii) the DSU declares a bid to reduce demand reduction at a declared bid price.

In principle, compensation arrangements in the revised Phase 1 solution could be the same as for positive demand reductions. This is because the overall demand reduction is positive (or zero), with only demand reduction specifically in the Balancing Market being negative.

If, on the other hand, demand reduction were characterised by reference to the proportion of hours it is providing demand reduction, or by changes in load from normal or current consumption patterns, DSUs persistently selling constant or near constant demand reduction in the ex ante market, or persistently submitting in-merit offers for demand reduction to the Balancing Market, might not be regarded as being demand reduction. Another approach might be to define the baseline methodology such that constant demand reductions, whether due to constantly-accepted offers or a constant FPN, would be absorbed into the baseline, such that they ceased to be demand reductions relative to the baseline.

What determines an appropriate decremental bid price is discussed in Section 4. However, on the assumption that, typically, bid prices are lower than prevailing market prices then the ability to declare negative demand reduction creates the opportunity for DSUs to arbitrage prices, in particular to sell demand reduction at an ex ante price and buy it back again at lower price. Put another way, it affords some customers the ability to buy demand at lower prices than other customers. Providing such demand is genuinely controllable then this may be appropriate. Nevertheless, the SEM Committee would welcome views as to whether there is potential for perverse outcomes or discrimination against other customers.

4. Other Aspects of a Revised Phase 1 Solution

4.1. Capacity

The SEM Committee recognises that there has been some discussion regarding the calculation of Derating Factors for DSUs. Nevertheless, the only aspect of capacity that the SEM Committee wishes to address in this consultation concerns the netting of Capacity Payments and Charges, and the appropriate adjustment to PCOMP.

Analogous to the treatment of energy payments, as discussed in Section 3, the compensation models for capacity for DSUs, in principle, include:

Model 1: Implicit Capacity Payments

In this model, DSUs would not be paid explicit Capacity Payments. Instead, demand reduction would simply reduce the amount of capacity that must be procured to secure the system, which would be reflected in lower Capacity Charges.

Given that Capacity Charges to suppliers are charged on a per MWh basis, whereas Capacity Payments to DSUs or other Generator Units are paid on a per MW basis, it follows that for DSUs with low capacity factors the savings in Capacity Charges for their IDSs are likely to be relatively low, resulting in underinvestment in this type of DSU. In contrast, for DSUs with high capacity factors, such as long-run DSUs, the savings in Capacity Charges for their IDSs are likely to be relatively high.

In addition, Capacity Charges to suppliers are profiled to an extent using the Capacity Charge Metered Quantity Factor. If suppliers profile their retail rates accordingly then we might expect savings to be passed on to the customer and hence to the DSU (if different). However, if the supplier charges are charged to the customer at a flat rate then, at times when demand reduction is most likely to be called, the customer will see only some of the saving that accrues to the supplier.

Model 2: Explicit Capacity Payments

In this model, the DSU is paid explicit Capacity Payments, in respect of the demand reduction capacity. If DSUs can compete for, and be paid, explicit Capacity Payments then, to achieve the same level of system security, it is important that enough capacity is procured to secure the 'unreduced' level of system demand, i.e. ignoring the reduction in demand from DSUs.

In the case of low capacity factor DSUs, it will make little difference to their IDSs whether Capacity Charges are levied on the unreduced or reduced demand. However, in the case of high capacity factor DSUs and their IDSs, levying Capacity Charges on the reduced level of demand will reward the demand reduction twice over. Similarly to energy payments, levying Capacity Charges on non-consumed energy, in addition to metered quantities, will avoid this double counting, but will require the supplier to bill the customer for Capacity Charges on non-consumed energy, in addition to metered quantities, and then is likely to be reflected in the terms between the customer and the DSU.

Model 3: Explicit Capacity Payments with Supplier Compensation

Analogous to energy payments, the third model is that the supplier pays Capacity Charges on the basis of the unreduced demand but, rather than charging the customer, is compensated directly by the DSU.

Revised Phase 1 Solution

As with energy payments, in a revised Phase 1 solution it will not be possible to identify the suppliers that have been directly affected by the demand reduction, such that Capacity Charges can be levied on the non-consumed energy. However, rather than compensating the supplier, in the revised Phase 1 solution, the DSU pays compensation to the TSC. As with energy payments, the compensation should be representative of the charge that the supplier would have levied on the customer. In practice, it may be appropriate that this is on the same basis, i.e. per MWh, as the supplier compensation price, and hence could take the form of an uplift to the supplier compensation price. The SEM Committee would welcome views on this approach.

4.2. Baselining

Currently, DSUs in the SEM are dispatched and, rather than being metered, are deemed to have fully delivered on their dispatch instructions, by setting Metered Quantity (QM) equal to the Dispatch Quantity (QD). If implemented in any enduring solution then, in the event that the DSU fails to deliver any demand reduction, or delivers less demand reduction than dispatched, the shortfall in delivery will be reflected in higher than appropriate correction to the supplier's imbalance, i.e. the

Metered Quantity plus non-consumed energy will be deemed to have been higher than would otherwise be the case. Any such underperformance may, in the long-run, be reflected in the procurement of more capacity. However, in the short term, it is likely that any such underperforming capacity could displace more reliable capacity, and thereby reduce system security.

It is desirable, thus, that demand is baselined to give a better measure of the demand that would have been consumed had the demand reduction not been dispatched.

There are many approaches to baselining, although a recognised approach is to calculate a profile based on the average of similar days in a defined period, such as the previous quarter, potentially with corrections for, say, the level of demand immediately preceding the dispatch of the demand reduction, or the temperature on the day in question. Baselining periods need to be short enough to ensure that they can be representative of the conditions when demand reduction is dispatched, but long enough to minimise the risk they can be manipulated to enhance the perceived amount of demand reduction.

As with the supplier compensation price, it would seem appropriate that any baselining methodology be enshrined in a methodology statement, subject to change control and regulatory approval. Detailed consultation would be required, but the SEM Committee would welcome any views at this stage.

4.3. Metering

Rather than baselining a demand site comprising uncontrolled and uncertain demand-consuming processes combined with a dispatchable demand reduction, an alternative is to meter just the dispatchable demand reduction. Typically, this will involve 'sub-metering' of controllable processes and/or on-site generation. The uncontrolled and uncertain demand is then determined by differencing the metering for the whole site and the sub-metered demand reduction. The proposed NCDR contemplates the use of such sub-metering to measure the delivery of demand response services.

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, which prescribes that, “*All market participants shall be responsible for the imbalances they cause in the system*”, and with Article 17(3)(d) of the Electricity Directive which prescribes that, “*Member States shall ensure that their relevant regulatory framework contains … an obligation on market participants engaged in aggregation to be financially responsible for the imbalances that they cause in the electricity system*”.

Also, the Trading and Settlement Code requires that each demand site associated with the DSU must meet the following criteria:

(i) the demand site shall have the technical and operational capability to deliver demand reduction in response to dispatch instructions from the relevant System Operator in accordance with the relevant Grid Code or Distribution Code; and

(ii) the demand site shall have appropriate equipment to permit real-time monitoring of delivery by the relevant System Operator.

Moreover, the SEM Committee understands that the TSOs currently make use of SCADA data provided by each DSU operator. This data is used to determine the “Demand Side Unit Calculated MWh Response”, in order to determine compliance under the Grid Code with Dispatch Instructions. The SEM Committee considers that, going forward, DSU Metered Quantity could be based on this quantity. This approach would not place any new obligations on DSUs, given that the data is already required to be submitted under the Grid Code and hence is already available. The SEM Committee would welcome views on the use of such data for DSU settlement.

4.4. Dynamic Retail Tariffs

Retail tariffs are not a SEM Matter. Nevertheless, the CRU, as part of its Active Consumer and Energy Communities initiative, is currently developing a dynamic retail tariff obligation to apply to large suppliers of domestic customers with smart metering.

Dynamic retail tariffs will include an element of pass-through of wholesale market prices. They are required under the Clean Energy Package[14], and are expressly intended to make customers more responsive to real-time prices, i.e. to encourage implicit demand response. By doing so, the DSU missing money is reduced. The purest manifestation of a dynamic retail tariff would be where the supplier completely passes through the wholesale price, charging the customer the wholesale price (including the Imperfections Charge and Capacity Charge and other market charges), plus network charges, supplier's internal costs and supplier's margin. Here, the missing money problem would be eliminated entirely, with the customer's purchase cost savings providing an efficient signal for demand reduction. In effect, the role of the aggregator becomes less about providing explicit demand response and more about helping customers to manage their purchase costs.

With arrangements that make energy payments to DSUs, 100% cost pass-through implies that the appropriate supplier compensation payment is equal to, or based on, the Imbalance Price, or a mixture of the Imbalance Price and ex ante price, plus the Imperfections Charge, Capacity Charge, etc. As such, less of the incentive for demand reduction will come from the difference between these two cashflows and more from the customer's savings in purchase costs. That said, even with 100% cost pass-through, there is likely to remain value in explicit demand response, to the extent that explicit demand response provides the TSOs with more certainty of response[15], as well as providing system services.

For the duration of a revised Phase 1 solution, it is unlikely that there will be widespread take-up of dynamic retail tariffs. Also, most demand response is currently provided by industrial or commercial customers to whom dynamic retail tariff obligations do not currently apply, with the degree of wholesale price pass-through being a matter of negotiation between the customer and the supplier. If the price paid by the customer is more dynamic than the supplier compensation payment price then the incentive for demand reduction, comprising the customer's savings in

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[14] EU Directive 2019/944, Article 12.

[15] In principle, when an offer is accepted by the system operator, the balancing service provider is simply responding to the price signal provided by the offer price. However, in practice, dispatch instructions are accompanied by obligations to deliver the relevant volume, regardless of the price that was offered.

purchase costs and the difference between SEM revenues and supplier compensation payments, could exceed the efficient level, in principle, resulting in demand reduction when none is warranted.

4.5. Availability Declarations

The SEM Committee wishes to raise two issues regarding availability declarations from DSUs. Firstly, that some DSUs are not declaring an availability of 4 MW or above; and, secondly, the rounding of availability to whole numbers of MW.

Demand Side Unit MW Capacity is defined in the Grid Code as, "*The maximum change in Active Power that can be achieved by a Demand Side Unit on a sustained basis for the duration of the Demand Side Unit's Maximum Down Time by totalling the potential increase in on-site Active Power Generation and the potential decrease in on-site Active Power Demand at each Individual Demand Site."*

Under the Grid Code, a DSU must have a Demand Side Unit MW Capacity of at least 4 MW. However, the SEM Committee understands that some DSUs are not declaring an availability of 4 MW or above, and indeed some DSUs are not declaring an availability above 1 MW. While the SEM Committee recognises that, due to the nature of demand response aggregation across multiple demand sites, some DSUs may not be able to declare an availability of 4 MW or above at all times, the SEM Committee considers that every DSU should be declaring an availability of 4 MW or above on a regular basis.

Regarding rounding, EDIL, which is used by Generator Units, including DSUs, to submit availability declarations to the TSOs, can currently accept only whole numbers of MW. The SEM Committee understand that some DSU operators are rounding up actual availability, e.g. 1.1 MW is declared as 2MW. The TSOs have previously recommended that availabilities be rounded to the nearest MW, e.g. 1.4 MW is rounded down to 1 MW and 1.6 MW is rounded up to 2 MW, although it is understood that some DSU operators continue to round up in all cases, nonetheless.

SDC1.4.1.3 of the Grid Code states that availabilities must be declared as whole numbers, while SDC1.4.3.4 requires that declared availabilities (and other technical parameters) are achievable. Taking these two conditions together, it implies that declared availabilities should be rounded down in all cases, so as to ensure the declared value is always achievable.

It is recognised, though, that the current proposed NCDR requires TSOs to develop a roadmap to allow bid granularity to be reduced to 0.1 MW[16].

Further, the SEM Committee notes that some demand response may already be participating in other demand reduction programmes, such as ESBN's 'Beat the Peak'. It is for consideration whether such demand response should be also declaring availability into the SEM, or whether these other programmes should be amended to fit in with the wholesale market arrangements rather than the other way around.

4.6. Bidding

The SEM Committee is aware of issues relating to the bidding of DSUs. While these issues may warrant clarification in the Bidding Code of Practice, in the meantime, bidding cost-reflectively is a condition of the licences issued to DSU operators.

One issue relates to Shutdown Costs (which are equivalent to generator Start-Up Costs). It is understood that each IDS is likely to have a shutdown cost associated with making a demand reduction. However, the SEM Committee does not consider that the Shutdown Cost for a DSU, comprising two or more such IDSs, should necessarily be the sum of the shutdown costs for the IDSs. This would be to assume that any demand reduction is effected by starting demand reduction at all the IDSs in the DSU, whereas it seems more likely, and efficient, that each IDS is shut down and provides a substantial proportion, if not all, of available demand reduction, before demand reduction is initiated at the next IDS. As such it may be more appropriate to spread the shutdown cost over the available MW of demand reduction of each IDS[17], on the basis that shutdown costs incurred by the DSU are not fixed and will increase as the DSU demand reduction is increased. Certainly, where the availability of a DSU reduces due to a particular IDS no longer offering

[16] Article 29(1).

[17] The most accurate representation would be to provide for a number of intermediate Shutdown Costs, as the amount of demand reduction is gradually increased. However, both scheduling and dispatch systems, and the TSC, provide only for a single Shutdown Cost. To do otherwise, would be equivalent to bidding each IDS individually, without aggregation.

demand response, the shutdown cost for that IDS should no longer be reflected in the COD for the DSU. The SEM Committee would welcome views on the appropriate treatment of IDS shutdown costs.

A second issue relates to decremental bid prices.   In particular, the SEM Committee understands that some DSUs have been declaring decremental prices that are very negative, particularly where demand reduction is effected by on-site CHP generation. These bids have been accepted by the TSOs, where it is necessary to do so to minimise curtailment of generators with priority dispatch. As a result, some DSUs have been paid to *not* reduce demand. The SEM Committee would welcome views on the cost-reflectivity of negative decremental bids.

The RAs' Market Monitoring Unit (MMU) is planning to issue guidance regarding DSU bidding and may consult further in respect of such guidance.

4.7. Aggregated Generating Units

The TSC and Grid Code have provision for Aggregated Generating Units (AGU)[18], being a group of Generating Units, each with a Registered Capacity of less than 10MW. In principle, any on-site generation that is included in a DSU could, instead, be included in an AGU.

Such units could be traded in the SEM in the same manner as other Generator Units and would be exposed to wholesale market prices and would receive the same payments as other Generator Units. Metering arrangements would ensure that the output of behind-the-meter Generating Units, which are aggregated as part of an AGU, is correctly taken into account when deriving the relevant demand site's metered demand and is not double counted in Supplier Unit demand.

[18] "Aggregated Generating Units" in the Grid Code, but "Aggregated Generator Unit" in the Trading and Settlement Code.

5. Views Invited and Next Steps

Demand response will become increasingly important in meeting decarbonisation targets with intermittent generation from renewable sources. Opportunities for explicit demand response in the SEM (or in other markets) generally arise where demand is exposed to some form of average price - such as a supplier charging a fixed tariff - which does not fully reflect the value of time or location. Wholesale market arrangements for explicit demand response aim to expose at least some demand to this value.

Newer market designs are aiming to better reflect the value of time and of flexibility (e.g. the change from the pre-2018 SEM to the new SEM), and of location (e.g. locational marginal pricing in US models, and as may be contemplated in the EU[19]). Dynamic retail tariffs then expose customers to these signals. By exposing demand to these signals, these developments intend to promote implicit demand response but, by the same token, they may also erode opportunities for explicit demand response. However, there is likely to remain value in explicit demand response, to the extent that explicit demand response, as provided by DSUs, gives the TSOs more certainty of response and can provide system services.

The SEM Committee recognises that there are issues in the current SEM that may create incentives for DSUs to minimise rather than maximise availability at times when demand response could be of most value to the system, and that exposing DSUs to wholesale prices through energy payments should mitigate this problem. However, the SEM Committee also recognises that in the Phase 1 solution, as proposed in SEM-22-090, the absence of charges for the non-consumed energy either on the affected supplier or on the DSU risked imposing an unreasonable and unwarranted burden on end customers, by the double counting of the energy payments and supplier savings for long-run DSUs. This consultation paper has discussed possible ways of addressing this, either:

(i) by including a supplier compensation payment, albeit paid not to the supplier affected by the demand reduction (which cannot be identified in the Phase 1

[19] "Reform of Electricity Market Design", Commission Staff Working Document, SWD(2023) 58 final

solution) but to all suppliers which are financially impacted by increased Imperfections Charges (that fund the energy payments to DSUs); or

(ii) by limiting eligibility for energy payments only to DSUs that, in the SEM Committee's view, comply with the definition of demand response; or

(iii) both.

The SEM Committee considers that the Phase 1 solution need not consist of a single package of changes, all of which need to be implemented in one go, but can involve a series of changes most of which can be implemented individually, as and when appropriate. Thus, in addition to TSC changes for the introduction of energy payments and supplier compensation, the consultation paper has discussed further potential changes, including: baselining; sub-metering; setting metered quantity for DSUs based on their "Demand Side Unit Calculated MWh Response" as per the Grid Code; and better facilitating Aggregated Generating Units.

Further work on the enduring solution will await finalisation of the Network Code on Demand Response, and a full consideration of its implications.

5.1. Views Invited

The SEM Committee invites views from all stakeholders on all of the discussion and issues raised in this consultation paper, especially answers to the consultation questions set out in Appendix A, plus any other issues stakeholders may consider relevant.

Responses to this consultation paper should be sent to both tsc@cru.ie and caroline.winder@uregni.gov.uk by close of business on 04 October 2024. It would be appreciated if responses are submitted in searchable PDF or Microsoft Word format.

Unless marked confidential, responses will be published on the SEM Committee website. Respondents may request that their response is kept confidential, and such request will be respected subject to any legal disclosure requirements. Respondents who wish to have their responses remain confidential should clearly mark their response to that effect and include the reasons for confidentiality. Confidential information should be contained in a separate appendix, if possible, to allow publication of the rest of the response.

The SEM Committee will carefully consider all comments received, with a view to publishing a decision and working with SEMO and the TSOs on making the appropriate modifications and amendments to the TSC and/or other documents. Some detailed issues may require further consultation.

Appendix A: Consultation 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.

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

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

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

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

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

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

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

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

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

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

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

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.

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.

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.

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

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

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.

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.

Appendix B: Demand Reduction Cashflows

The three hypothetical models described in Section 3.4, and the revised Phase 1 solution described in Section 3.5, are discussed here further, and shown diagrammatically.

Model 1: No DSU Energy Payments

Figure 1 shows the change in TSC cashflows for a demand reduction in Model 1 (No DSU Energy Payments). In this model, there is no correction to the supplier's Metered Quantities, so that any demand reduction will result in a reduction in demand taken by the supplier's customer. This will make the supplier's imbalance less positive, and lead to reduction in Imbalance Charge (for positive imbalances) or increase in Imbalance Payment (for negative imbalances). Hence the demand reduction results in a change in cashflow, priced at the Imbalance Price (PIMB), in favour of the supplier. Were the supplier able to anticipate the demand reduction, it could, at least in principle, reduce its ex ante purchases, such that the demand reduction would result in a cashflow in the supplier's favour, priced at the ex ante price.

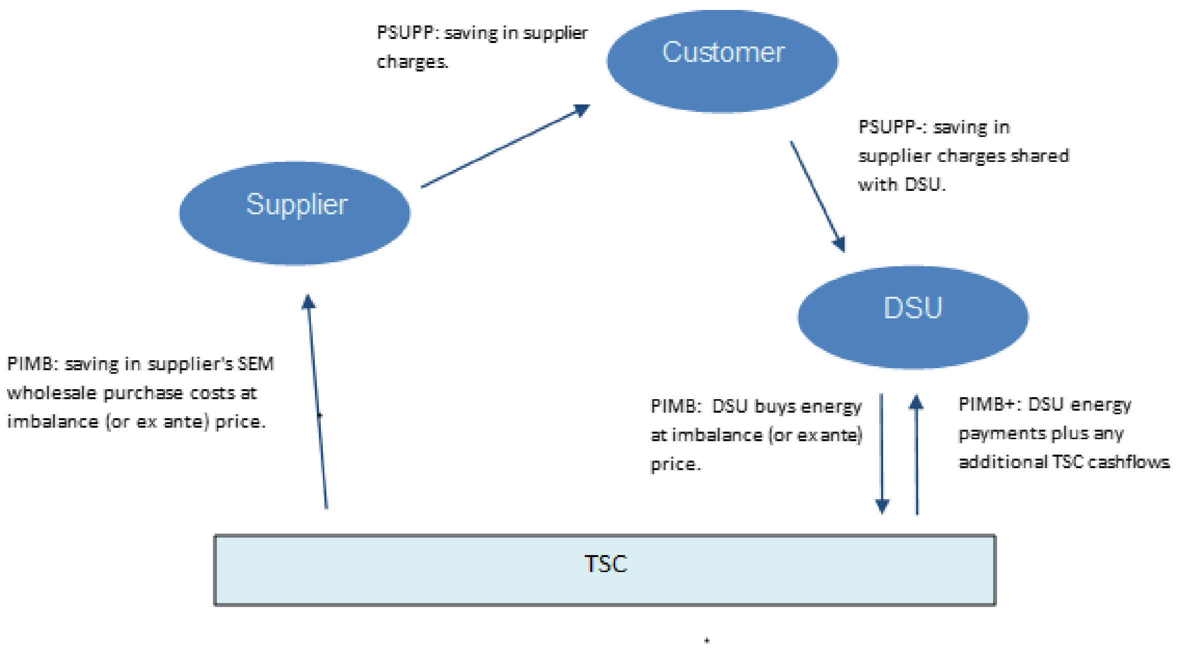

Figure 1: Model 1 (No DSU Energy Payment)

As a result of the demand reduction, the supplier will be able to bill the customer only for a lower quantity. Hence, there is a change in cashflow in favour of the customer, priced at the price, PSUPP, specified in the contract between the supplier and the customer.

The DSU will either (i) be paid DSU energy payments plus any additional TSC cashflows, such as CPREMIUM or additional shutdown payments, but have to buy the "non-consumed" energy at the Imbalance Price, PIMB; or (ii) be paid just the additional TSC cashflows. Under the first of these two options, the DSU has the option to sell some or all of the demand reduction, and buy the non-consumed demand, in the ex ante markets, in which case the demand reduction and the non-consumed demand may be priced at the ex ante price rather than PIMB.

Although it is a private matter between the customer and the DSU (if a separate party), the customer may share some of the savings in supplier charges with the DSU, at some price, $PSUPP^-$. The sharing arrangement will depend on which party bears the cost of effecting the demand reduction, whether that be the loss of value that would have been derived from consuming the energy, e.g. in a manufacturing process, or the cost of running on-site generation.

There is a net cost of the balancing action being provided by the demand response to the TSC of $PIMB^+$, being the Imbalance Price plus the additional TSC cashflows such as CPREMIUM and additional shutdown costs[20].

Model 2: DSU Energy Payments

Figure 2 shows Model 2 (DSU Energy Payments). Here, the DSU receives energy payments, but does not buy the non-consumed energy. Instead, the supplier is

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[20] While there is a net cost for the particular balancing action provided by the demand response, the demand response will have been called because it is less costly than alternative actions available to the TSO for balancing the system. This applies equally to low-cost, on-site generation which, if not traded as a long-run DSU, would be traded as explicit generation, i.e. as an AGU, or if not traded at all would simply be a reduction in demand purchased from the SEM; either way it displaces a more expensive alternative. Hence, overall, there should be no net cost, and even a net saving, to the system as a whole, as should be the case with any efficient balancing action. Note also that, as with any balancing action, the Imbalance Component will be funded by the corresponding quantity of demand, with the additional TSC cashflows being funded by Imperfections Charges.

obliged to buy the non-consumed energy, by correcting the supplier's imbalance to take account of the non-consumed energy[21]. Hence, the demand reduction does not result in any change in cashflow to the supplier.

The supplier will wish to recover the cost of purchasing the non-consumed energy from the SEM wholesale markets and will charge the customer accordingly, which implies that there will not be any savings for the customer to share with the DSU. However, the DSU will receive energy payments from SEM, whether at PIMB or the ex ante price, from which it will need to cover the costs of effecting the demand reduction. There will need to be a side payment from the DSU to the customer to cover these costs.

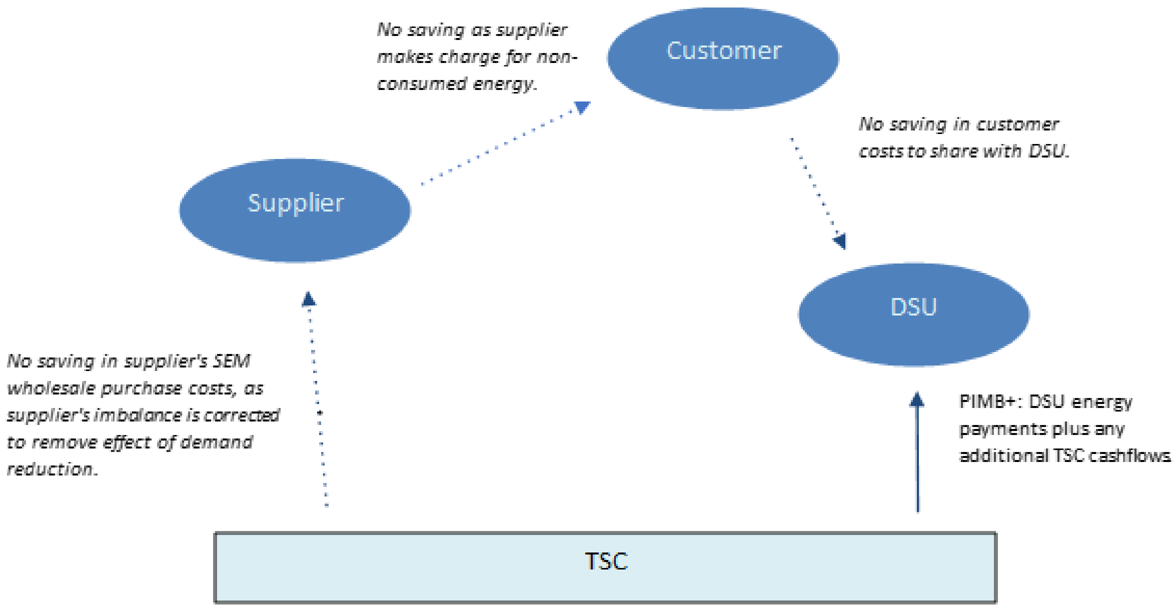

Figure 2: Model 2 (DSU Energy Payment)

As for Model 1, the net cost is PIMB^{+}.

Model 3: DSU Energy Payments with Supplier Compensation

In the last of the three hypothetical models, in Figure 3, the supplier's imbalance is, like in Model 2, corrected to account for the non-consumed energy. However, rather

[21] Whether the demand reduction and non-consumed energy are determined by metering of the demand reduction processes, by reference to a baseline, or is assumed to be equal to the Dispatch Quantity, is a separate issue.

than the supplier charging the customer for the non-consumed energy, the supplier bills the customer only for actual metered quantities, such that the demand reduction results in a cashflow in favour of the customer, priced at the supply price, PSUPP. In this model, the DSU compensates the supplier for the non-consumed energy, at a supplier compensation price, PCOMP.

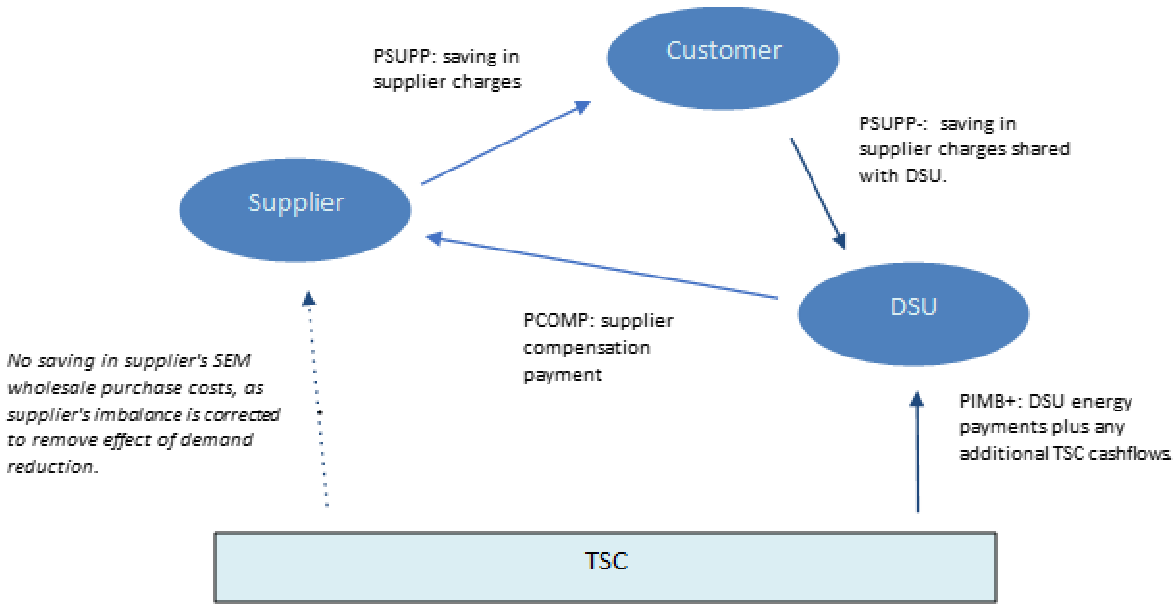

Figure 3: Model 3 (DSU Energy Payments with Supplier Compensation)

The DSU will receive energy payments from the TSC, priced at PIMB or, if sold forward, at the ex ante price. The difference between PIMB (or the ex ante price) and PCOMP provides the 'missing money' to the DSU discussed in Section 3. As agreed privately, the customer may share the savings in supply charges with the DSU. Although if the customer, rather than the DSU, bears the costs of effecting the demand reduction, the DSU is likely to have to compensate the customer for these costs.

As with Models 1 and 2, the net cost is $PIMB^{+}$.

Revised Phase 1 Solution

Finally, Figure 4 shows the revised Phase 1 solution, as discussed in Section 3.5. This is a modified version of Model 3. The specific difference is that, if the supplier cannot be identified, no correction can be made to the supplier's imbalance and, consequently, the supplier will benefit from a cashflow priced at PIMB (or the ex ante price). However, for the same reason, the supplier compensation payment cannot be made to the supplier. Instead, this is paid back to the Imperfections Charge fund, such that it reduces the overall cost to Imperfections of funding DSU energy payments.

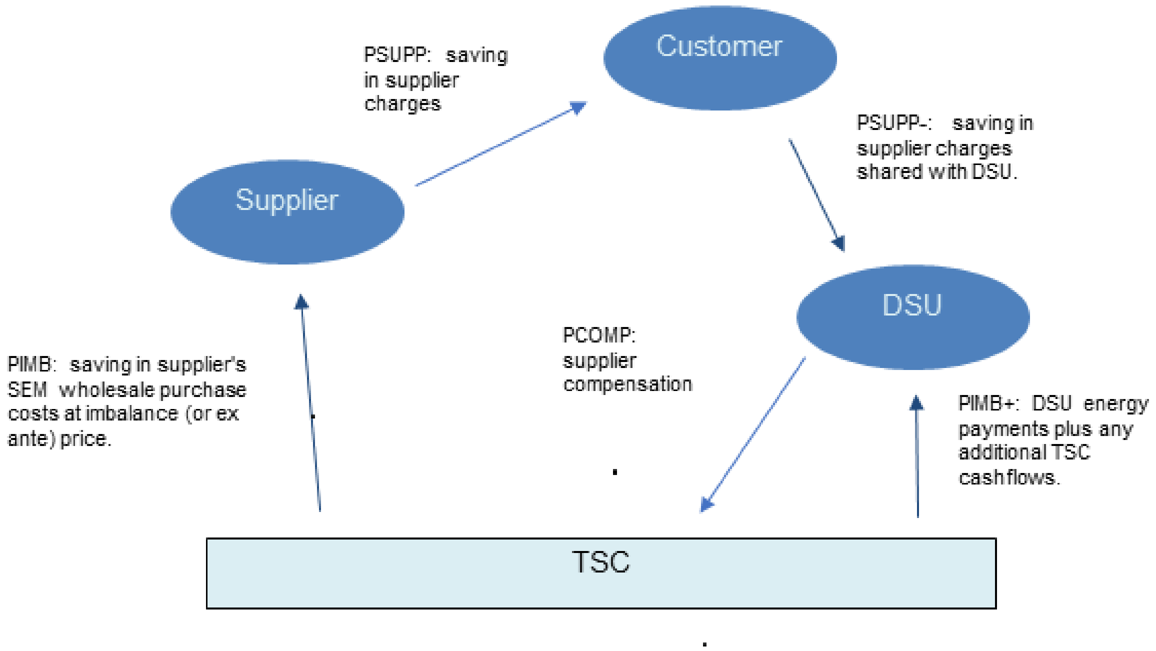

Figure 4: Revised Phase 1 Solution

For long-run DSUs, which are giving demand reduction most, if not all, of the time, typically because demand reduction is effected by low-cost, on-site generation, PCOMP should counter-balance the supplier's savings in wholesale purchase costs, such that the net cost is, as with Models 1 to 3, $PIMB^{+}$, reflecting the value of the generation to the system.

However, with intermittent demand reduction, which is dispatched at times of high prices, then supplier savings are likely to exceed PCOMP, and there will be an additional net cost, which will add to the cost of Imperfections. In effect, this cost arises because demand reduction is being double-counted both in savings to the supplier, and in energy payments to the DSU, and which double counting is not, at times of high prices, being compensated for by PCOMP.

Appendix C: Numerical Example Across the Different Models

In this appendix, an underlying scenario is outlined, and numerical examples are provided for this underlying scenario under the three hypothetical models described in Section 3.4 and under the revised Phase 1 solution described in Section 3.5.

Underlying scenario

The cost to the customer to provide demand reduction; and thus the DSU Offer Price to the wholesale market, is 400 €/MWh.

{For example, the cost to the customer of running an on-site diesel generator}.

The Imbalance Price = PIMB = 400 €/MWh.

{The DSU Offer Price and PIMB are set equal for simplicity in the examples. If the Customer cost / DSU Offer Price was greater than the PIMB, then the DSU would receive a CPREMIUM payment under each model, this doesn't change across models, and if the Customer Cost / DSU Offer Price was lower than the PIMB, then the DSU would receive inframarginal rent where it receives energy payments}.

The retail price that the customer is charged by its supplier = PSUPP = 150 €/MWh.

The Supplier Compensation Price = PCOMP = 130 €/MWh.
{Noting that Network Charges, some market charges, supplier costs and supplier margin are unlikely to be included in PCOMP, so it should be lower than the average retail price across the retail market}.

The "Baseline" demand of the customer = 3 MWh.

The demand reduction activated by the DSU / customer = "non-consumed energy" = 1 MWh.

The metered demand of the customer = 2 MWh.

Model 1: No DSU Energy Payments

The customer buys its metered demand from its supplier at PSUPP (2 MWh @ 150 €/MWh).

The customer saves €150 in supplier charges by not buying the "non-consumed energy" from the supplier (1 MWh @ 150 €/MWh).

The supplier buys the customer's metered demand from the wholesale market (2 MWh @ 400 €/MWh).

The supplier saves €400 in wholesale purchase costs by not buying the "non-consumed energy" (1 MWh @ 400 €/MWh).

The demand reduction cost the customer €400 to provide (1 MWh @ 400 €/MWh).

The DSU does not get paid the wholesale price.

The DSU/customer has a "missing money" problem of [cost to provide demand reduction minus saving in supplier charges] = [€400 minus €150 = €250].

The supplier benefit = [avoided wholesale purchase cost minus loss in supplier charges from customer] = [€400 minus €150 = €250].

Model 2: DSU Energy Payments

The customer buys its metered demand AND its "non-consumed energy" from the supplier (3 MWh @ 150 €/MWh).

The supplier buys the customer's metered demand AND the customer's "non-consumed energy" from the wholesale market (3 MWh @ 400 €/MWh).

The demand reduction cost the customer €400 to provide.

The DSU gets paid the wholesale price for the demand reduction (1 MWh @ 400 €/MWh).
{Note that this is funded by the supplier paying for the "non-consumed energy" at the wholesale price and no injection of money from the Imperfections Charge is required}.

The DSU/customer has no "missing money" problem.

Model 3: DSU Energy Payments with Supplier Compensation

The customer buys its metered demand from the supplier (2 MWh @ 150 €/MWh).

The customer saves €150 in supplier charges by not buying the “non-consumed energy” from the supplier (1 MWh @ 150 €/MWh).

The supplier buys the customer’s metered demand AND the customer’s “non-consumed energy” from the wholesale market (3 MWh @ 400 €/MWh).

The demand reduction cost the customer €400 to provide.

The DSU gets paid the wholesale price for the demand reduction (1 MWh @ 400 €/MWh.)
{Note that this funded by the supplier paying for the “non-consumed energy” at the wholesale price and no injection of money from the Imperfections Charge is required}.

The DSU pays the “supplier compensation price” to the supplier (1MWh @ 130 €/MWh).

The DSU/customer has no “missing money” problem.

Revised Phase 1 Solution

The customer buys its metered demand from the supplier (2 MWh @ 150 €/MWh).

The supplier buys the customer metered demand from the wholesale market (2 MWh @ 400 €/MWh).

The demand reduction cost the customer €400 to provide.

The DSU gets paid the wholesale price for the demand reduction (1 MWh @ 400 €/MWh).
{This is funded from the Imperfections Charge}.

The DSU pays the “supplier compensation price” back to the Imperfections Charge fund (1MWh @ 130 €/MWh).
{The net cost to the Imperfections Charges fund is the cost of wholesale energy payments to the DSU minus the supplier compensation price paid back to the fund by the DSU; €400 minus €130 in this example}.

The DSU/customer has no “missing money” problem.

Appendix D: Supplier Compensation Payment Methodologies

Some methods used in other electricity markets for calculating the price which DSUs pay to purchase the electricity they then sell as demand reduction (or to compensate suppliers) are outlined below.

Australia

In Australia, Demand Response Service Providers (DRSPs) are paid a regional spot price but must pay back a 'wholesale demand regional reimbursement rate' (WDRRR), in $/MWh, for every MWh of demand reduction.

The WDRRR for a region for a trading interval is the peak period load weighted average spot price for the regional reference node for the quarter in which the trading interval falls. Each quarter, AEMO (the Australian Energy Market Operator) must calculate and publish the peak period load weighted average spot price for each region for the prior 12-month period (ending immediately before the start of the quarter).

France

In France, the regulated rates of payment from DSUs to suppliers are explained in Article 10 of RTE's Terms and Conditions for Demand Response Participation in Energy Markets, NEBEF (Notification d'Échange de Blocs d'Effacement). The rates of payment are published on the RTE Customer Portal website. All revisions of these payment rates by RTE are valid on their date of publication on the Customer Portal.

The rates of payment are visible here: NEBEF compensation payment - RTE Services Portal (services-rte.com). The rates of payment for profiled consumption sites, under both the 'Base Rate Option' and the 'Non-Base Rate Option', as of 1 February 2024, are shown below.

Compensation payment (€ excl. tax /MWh)	Off-Peak Hours for the Profiled consumer (OPP)	Peak Hours for the Profiled consumer (PP)
Profiled consumption sites in Base rate option(1)	133,25	133,25
Profiled consumption sites in non-Base rate option (2)	53,33	197,90

Belgium

In Belgium, where the DSU and supplier cannot agree on a negotiated price on which to base the financial compensation from the DSU to the supplier, the "Transfer Price by Default" in €/MWh applies. The "Transfer Price by Default" is calculated by CREG (*Commission de Régulation de l'Électricité et du Gaz*, the Belgian Federal Commission for Electricity and Gas Regulation) based on CREG decision (B)1677.

CREG applies the following formula:

Transfer Price by Default

= { [73% * 1/3 (Cal Y+2 + Cal Y+1 + M+1)
+ 27% EPEXspot BE DAM] * 1.05 } +/- 5%

where:

"CAL Y+2" represents the average of daily quotes published by ICE ENDEX during the year two years preceding the year of activation for the baseload product (expressed in €/MWh);

"CAL Y+1" represents the average of daily quotes published by ICE ENDEX during the year preceding the year of activation for the baseload product (expressed in €/MWh);

"M+1" represents the average of daily quotes published by ICE ENDEX during the month preceding the month of activation for the baseload product (expressed in €/MWh); and

"EPEXspot BE DAM" is the quotation published by EPEX spot Belgium on the day ahead market for the time during which activation of demand reduction occurs (expressed in €/MWh). In the absence of a quote on the DAM, the last published quote is used.

Great Britain

Modification P415 to the Balancing & Settlement Code has recently been approved to provide for "Virtual Lead Parties", which fulfil broadly the same function as DSUs in the SEM.

P415 includes provision for a "Supplier Compensation Reference Price" and a "Supplier Compensation Reference Price Methodology Document".

It is understood that the Supplier Compensation Reference Price Methodology will be based on Ofgem's Price Cap Methodology which is designed to give a price that represents average supplier sourcing costs. The Price Cap Methodology has been used extensively for setting a cap on standard variable tariffs over a number of years.

Appendix E: Grid Code Provisions

Relevant Definitions

Demand Side Unit: 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.

Demand Side Unit MW Capacity: The maximum change in Active Power that can be achieved by a Demand Side Unit on a sustained basis for the duration of the Demand Side Unit's Maximum Down Time by totalling the potential increase in on-site Active Power Generation and the potential decrease in on-site Active Power Demand at each Individual Demand Site.

Demand Side Unit Best Correlated Profile: The four Demand Side Unit Profiles from one day to eighty-four days prior to the Dispatch Instruction, offset to minimise the average absolute error across all the Meter periods comprising the Demand Side Unit Profile when compared to the Demand Side Unit Profile which finishes with the Dispatch period, resulting in the four smallest average absolute errors, averaged.

Demand Side Unit Calculated MWh Response: The value of the quarter-hour Demand Side Unit Performance Monitoring Baseline less the sum of the quarter-hour Meter readings of all the Individual Demand Sites that comprise the Demand Side Unit aligned to a quarter-hour Meter period.

Demand Side Unit MW Availability: The forecasted change in Active Power which can be achieved in one currency zone by a Demand Side Unit for each Imbalance Settlement Period in the following Trading Day period and which must be submitted by the User to the TSO in an Availability Notice under SDC1.4.1.2.

Demand Side Unit MW Response: The proportion (in MW) of the Demand Side Unit MW Capacity that is delivered at a given time following a Dispatch Instruction from the TSO. This value will be zero unless dispatched by the TSO.

Demand Side Unit MWh Response: The equivalent Energy in a quarter-hour Meter period of a Demand Side Unit MW Response requested in a Dispatch Instruction.

Demand Side Unit Performance Monitoring Baseline: An Energy value for each quarter-hour Meter period while a Demand Side Unit is Dispatched. It is the Demand Side Unit Best Correlated Profile excluding the first forty-eight quarter-hour Meter periods.

Demand Side Unit Performance Monitoring Error: The absolute value of the Demand Side Unit Calculated MWh Response less the Demand Side Unit MWh Response.

Demand Side Unit Performance Monitoring Percentage Error: The absolute value of the Demand Side Unit Calculated MWh Response less the Demand Side Unit MWh Response divided by the Demand Side Unit MWh Response.

Demand Side Unit Profile: Consecutive aggregated Meter readings of all Individual Demand Sites that comprise a Demand Side Unit for each of the full quarter-hour Meter periods in a twelve-hour period plus the duration of Dispatch. If the Demand Side Unit was Dispatched during the period the Demand Side Unit Calculated MWh Response in the same quarter-hour Meter periods are added, except in the case of the Dispatch being monitored. In this case the accumulated Energy calculated from Demand Side Unit MW Response from Generation operating in Continuous Parallel Mode or Shaving Mode signal (CC.12.2 (i)) plus the Demand Side Unit MW Response from avoided Demand consumption and Generation operating in Lopping Mode, Standby Mode or Automatic Mains Failure Mode signal (CC.12.2 (m)) are added.

Demand Side Unit SCADA Error: The Demand Side Unit Calculated MWh Response less the accumulated Energy calculated from Demand Side Unit MW Response from Generation operating in Continuous Parallel Mode or Shaving Mode signal (CC.12.2 (i)) plus the Demand Side Unit MW Response from avoided Demand consumption and Generation operating in Lopping Mode, Standby Mode or Automatic Mains Failure Mode signal (CC.12.2 (m)) in the same quarter-hour Meter period.

Demand Side Unit SCADA Percentage Error: The Demand Side Unit Calculated MWh Response less the accumulated Energy calculated from Demand Side Unit MW Response from Generation operating in Continuous Parallel Mode or Shaving

Mode signal (CC.12.2 (i)) plus the Demand Side Unit MW Response from avoided Demand consumption and Generation operating in Lopping Mode, Standby Mode or Automatic Mains Failure Mode signal (CC.12.2 (m)) divided by Demand Side Unit Calculated MWh Response the in the same quarter-hour Meter period.

Relevant Provisions

CC.12.6

Demand Side Unit Operators and Generator Aggregators shall provide the TSO the specification of the method of aggregation of SCADA from multiple sites. The minimum specifications shall be agreed with the TSO in advance and shall include:

(a) signals from Demand Side Unit Operators shall be relayed to the TSO Telecommunication Interface Cabinet which reflect the Demand Side Unit MW Response to an accuracy of within 1 MW of the actual Demand Side Unit MW Response within 15 seconds of change occurring to the Demand Side Unit MW Response; and

(b) a single failure of an item of the Demand Side Unit Operator's equipment will not result in:

- (i) loss of control of more than one Individual Demand Site;
- (ii) loss of Demand Side Unit MW Response of more than one Individual Demand Site; or
- (iv) the Demand Side Unit MW Response from Generation or Demand Side Unit MW Response from avoided Demand consumption signals being incorrect by more than the Demand Side Unit MW Capacity of the Individual Demand Site with the highest Demand Side Unit MW Capacity comprising the Demand Side Unit.

OC.7.2.5.3.2

For Demand Side Unit Operators, SCADA remote terminal equipment shall also be required at the Control Facility for the transmission of signals and indications to and from the NCC. The signals and indications which must be provided by Demand Side

Unit Operators for transmission by SCADA equipment to the NCC are the signals and indications referred to under Connection Conditions together with such other information as the TSO may from time to time, by notice to Demand Side Unit Operators, reasonably require.

OC.10.4.5.2 Compliance of Demand Side Units with Dispatch Instructions

A Demand Side Unit shall be deemed compliant with a Dispatch Instruction if:

(i) the Demand Side Unit MW Response of the Dispatch Instruction is achieved in the Demand Side Unit MW Response Time and maintained until the subsequent Dispatch Instruction or until the Maximum Down-Time of the Demand Side Unit has elapsed; and

(ii) the Demand Side Unit Performance Monitoring Percentage Error is less than 5% for each full quarter-hour Meter period of the Demand Side Unit MW Response for 90% of the last ten Dispatches or 90% of the Dispatches in a three-hundred and sixty-five day period,

or

the Demand Side Unit Performance Monitoring Error is less than 0.250 MWh for each full quarter-hour Meter period of the Demand Side Unit MW Response in 90% of the last ten Dispatches or 90% of the Dispatches in a three-hundred and sixty-five day period; and

(iii) the Demand Side Unit Performance Monitoring Percentage Error is less than 10% for each full quarter-hour Meter period of the Demand Side Unit MW Response,

or

the Demand Side Unit Performance Monitoring Error is less than 0.250 MWh for each full quarter-hour Meter period of the Demand Side Unit MW Response; and

(iv) the Demand Side Unit Performance Monitoring Percentage Error is on average less than 5% for each full quarter-hour Meter period of the Demand Side Unit MW Response,

or

the Demand Side Unit Performance Monitoring Error is on average less than 0.250 MWh for each full quarter-hour Meter period of the Demand Side Unit MW Response; and

(v) the Demand Side Unit SCADA Percentage Error is less than 5% or the Demand Side Unit SCADA Error is less than 0.250 MWh.

OC.10.7.1.8

In the event that the Demand Side Unit Operator is deemed by the TSO in accordance with the provisions of this OC.10 to be in non-compliance with its Dispatch Instructions, that is the Demand Side Unit failed to comply with three (3) Dispatch Instructions in a one calendar month period then the TSO shall notify the Demand Side Unit Operator of the continued non-compliance. The Demand Side Unit Operator shall take immediate action to remedy such non-compliance. The terms of this OC.10.7.1.8 shall be without prejudice to the rights of the TSO to instruct the Market Operator that the Demand Side Unit is in breach of the Grid Code. In such cases the TSO may set the Demand Side Unit's Availability to zero or to a level as deemed appropriate by the TSO until Testing is completed on compliance with Dispatch Instructions.

SDC1.4.1.3 Whole Numbers

The MW figure stated in the Availability Notice shall be a whole number.

SDC1.4.3.4 Availability of Demand Side Units

Each Demand Side Unit Operator shall, subject to the exceptions in SDC1.4.3.5 and SDC1.4.3.5A, use reasonable endeavours to ensure that it does not at any time declare the Demand Side Unit MW Availability and the Demand Side Unit characteristics of its Demand Side Unit at levels or values different from those that the Demand Side Unit could achieve at the relevant time. The TSO can reject declarations to the extent that they do not meet these requirements.

SDC1.4.3.5

SDC1.4.3.4 shall not apply to the extent:

(a) it would require the Demand Side Unit Operator to declare levels or values better than Demand Side Unit MW Capacity and Technical Parameters as submitted under the Planning Code in respect of a Demand Side Unit;

(b) necessary during periods of Scheduled Outage or Short Term Scheduled Outage or otherwise with the consent of the TSO;

(c) necessary while repairing or maintaining the Demand Side Unit or equipment necessary to the operation of the Demand Side Unit where such repair or maintenance cannot reasonably, in accordance with Prudent Utility Practice, be deferred to a period of Scheduled Outage or Short Term Scheduled Outage.

(d) necessary to avoid an imminent risk of injury to persons or material damage to property (including the Demand Side Unit);

(e) it is not lawful for the Demand Side Unit Operator to change its Demand Side Unit MW Response or to operate its Demand Side Unit.

SDC1.4.3.5A

SDC1.4.3.4 shall not apply for a Demand Side Unit that is disconnected during any one or more of the following:

(a) Any TSO scheduled Annual Maintenance Outage or portion thereof on the Outturn Availability Connection Asset lasting up to and including a maximum of five days in total in a calendar year; or

(b) Where work to the Transmission System is being carried out that is driven by the relevant Demand Side Unit or driven by works related to Connection Agreement of the relevant Demand Side Unit. This does not include work carried out to another Generating Unit with a different Connection Point but a shared asset.

The relevant Demand Side Unit shall declare Availability at a value of zero during any one or more of (a) or (b) above, as advised by the TSO.

Appendix F: References

[1] State aid No. SA.44464 (2017/N) – Ireland – Irish Capacity Mechanism, C(2017) 7789 final, European Commission, 24 November 2017.

[2] State aid No. SA.44465 (2017/N) – United Kingdom – Northern Irish Capacity Mechanism, C(2017) 7794 final, European Commission, 24 November 2017.

[3] Regulation (EU) 2019/943 of the European Parliament and of the Council on the internal market for electricity", 5 June 2019.

[4] "Directive (EU) 2019/944 of the European Parliament and of the Council on common rules for the internal market for electricity and amending Directive 2012/27/EU", 5 June 2019.

[5] "Capacity Remuneration Mechanism DSU Compliance with State Aid. Decision Paper", SEM-19-029, July 2019.

[6] "DSU State Aid Compliance Interim Approach", SEMO, Mod_17_19 V2, 21 November 2019.

[7] "Enduring Solution to Enable Energy Payments in the Balancing Market for DSUs – A Consultation", SEM-22-036, 4 July 2022.

[8] "Enduring Solution to Enable Energy Payments in the Balancing Market for DSUs – Decision Paper", SEM-22-090, 25 November 2022.

[9] "Constraints Costs (Imperfections Charges) October 2023 – September 2024 and Reforecast Report October 2021 – September 2022. Consultation Paper", SEM-23-049, June 2023.

[10] "Framework Guideline on Demand Response", ACER, 20 December 2022

[11] "Proposal for a Network Code on Demand Response", EU DSO Entity and ENTSO-E, 8 May 2024.

[12] "Demand response and other distributed energy resources: what barriers are holding them back?", 2023 Market Monitoring Report, ACER, 19 December 2023.

[13] “"Reform of Electricity Market Design", Commission Staff Working Document, SWD(2023) 58 final.