Demand Side Units: Supplier Compensation Price

Consultation Paper

SEM-26-019

13 May 2026

EXECUTIVE SUMMARY

The SEM Committee recently published a proposed decision (SEM-26-017) regarding a “Revised Phase 1 Solution” to making energy payments to Demand Side Units (DSUs). Without such energy payments, at times of high wholesale market prices, a customer's savings in supplier charges at the supply tariff (in other words the savings from receiving a lower bill from their supplier as a result of reducing demand) may be insufficient to cover the cost of making demand reductions even when they are efficient for the system.

However, to ensure the incentives for demand reduction are appropriate, it is necessary that demand reduction (or 'non-consumed energy') is not compensated twice, both through energy payments to the DSU aggregator and again through savings in supplier charges for the customer.

Hence, in addition to energy payments to the DSU aggregator, the Revised Phase 1 Solution involves a supplier compensation payment whereby the DSU aggregator refunds the savings in supplier charges, with this refund being made to suppliers via the Imperfections fund. This compensation payment is calculated as the quantity of the demand reduction multiplied by a Supplier Compensation Price. This paper consults on the determination of the Supplier Compensation Price.

It is suggested that the Supplier Compensation Price should be fixed, rather than including a dynamic or time-of-use element, as a dynamic Supplier Compensation Price would risk under-compensating demand reduction where the customer has a flat tariff from their supplier, whereas this risk does not arise when the Supplier Compensation Price is also flat/fixed.

Quantifying the relevant energy costs to use in the Supplier Compensation Price is discussed. The approaches taken in electricity markets in Australia, Belgium, France and Britain are described. Options for the SEM are considered, including using the Directed Contract prices or alternatively averaging historic DAM or balancing market prices. Averaging periods, frequency of updates and weightings are considered.

Other costs to consider in determining the Supplier Compensation Price are discussed, comprising Imperfections, Capacity, Market Operator charges, other

Trading and Settlement Code charges, System Services charges, network charges, hedging costs, supplier costs and margins, losses and taxes and levies. The possibility that the Supplier Compensation Price should be jurisdictional is considered.

The paper poses a number of consultation questions, and views are invited by 10 July 2026. Responses should be submitted by email to tsc@cru.ie and tsc@uregni.gov.uk.

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Glossary of Terms and Abbreviations

Abbreviation or Term	Definition or Meaning
ACER	Agency for the Cooperation of Energy Regulators
BSC	GB Balancing & Settlement Code
CREG	Commission de Régulation de l'Électricité et du Gaz
CRU	Commission for Regulation of Utilities
DSU	Demand Side Unit
EBGL	Electricity Balancing Guidelines
EEX	European Energy Exchange
EPEX	European Power Exchange
EU	European Union
ICE ENDEX	Intercontinental Exchange
ICIS	Independent Commodity Intelligence Services
IDS	Individual Demand Site
NCDR	Network Code for Demand Response
NEBCO	Notification d'Echange de Blocs de Consommation
PCOMP	Supply Compensation Price.
QMLF, PIMB, PIMP, PCCSUP, PVMO, PREV, PCC, FQMCC, CVMO, FNIEP, RMVIP.	As defined in the Trading & Settlement Code
PSO	Public Service Obligation
RTE	Le Reseau de Transport d'electricite
SEM	Single Electricity Market
SEMO	Single Electricity Market Operator
TSC	Trading and Settlement Code
TSO	Transmission System Operator
WDRRR	Wholesale Demand Regional Reimbursement Rate

1. Introduction

The SEM Committee recently published a proposed decision[1] ("the Proposed Decision Paper") regarding a “Revised Phase 1 Solution” to making energy payments to Demand Side Units (DSUs). The approach involves, in addition to energy payments to the DSU aggregator, a supplier compensation payment made by the DSU aggregator to suppliers via the Imperfections fund, which payment is calculated as the quantity of the demand reduction multiplied by a Supplier Compensation Price.

This paper, which should be read in conjunction with the Proposed Decision Paper, consults on the determination of the Supplier Compensation Price.

The structure of the paper is as follows:

Section 1: is this introduction;

Section 2: discusses the principles in determining Supplier Compensation Price, including what costs should be considered and whether or not Supplier Compensation Price should be time should be time-varying;

Section 3: considers energy costs, including the approach taken in other electricity markets and options for the SEM;

Section 4: considers other costs; and

Section 5: invites views.

There are three appendices:

Appendix A: lists consultation questions;

Appendix B: shows extracts from existing and proposed EU legislation; and

Appendix C: lists relevant documents.

[1] "Demand Side Units: A Revised Phase 1 Solution for Energy Payments and Other Issues: Proposed Decision Paper", SEM-26-017, 31 March 2026.

2. Principles for Determining Supplier Compensation Price

2.1. Energy Costs

The Proposed Decision Paper and preceding consultation paper[2] ("the Consultation Paper") discussed supplier compensation payment as a means of ensuring that demand reduction in the form of a DSU is efficiently dispatched, appropriately incentivised and put on an equal footing with generation.

While energy payments to DSUs for demand reductions are necessary to ensure the cost of making efficient demand reductions are covered at times of high prices, a corollary of making such energy payments is that, in a process commonly referred to as “perimeter correction”, the supplier of the customer making the demand reduction at each Individual Demand Site (IDS) should be required to buy the "non-consumed energy" by deeming the supplier's Metered Quantity in the Trading and Settlement Code (TSC) to include the demand the customer would have taken had the demand reduction not occurred. Without perimeter correction, demand reduction would be rewarded twice: once through the energy payments to the DSU and a second time through the supplier’s avoided costs of buying from the wholesale market. In the SEM this double payment would manifest itself in an increase in Imperfections Charges. In one model for DSU cashflows, the supplier bills the customer for the non-consumed energy. It is to be expected that the customer would seek recompense for this cost through the commercial arrangements it agrees with the DSU aggregator, which the DSU aggregator would fund from the energy payments it receives. In a second model, compensation is paid to the supplier by the DSU aggregator, allowing the supplier to bill the customer for only the metered demand and avoiding the need to bill the customer for electricity it didn’t consume. In effect, the compensation in this second model refunds to the supplier the savings in supplier charges that arise in addition to the energy payments, which savings would not occur in the first model. (See Figure 1.) As with most wholesale market cashflows, the payment from the DSU to the supplier is made not through a direct bilateral agreement but via the market operator.

[2] “Demand Side Units: A Revised Phase 1 Solution for Energy Payments and Other Issues: Consultation Paper” SEM-24-046, 23 August 2024.

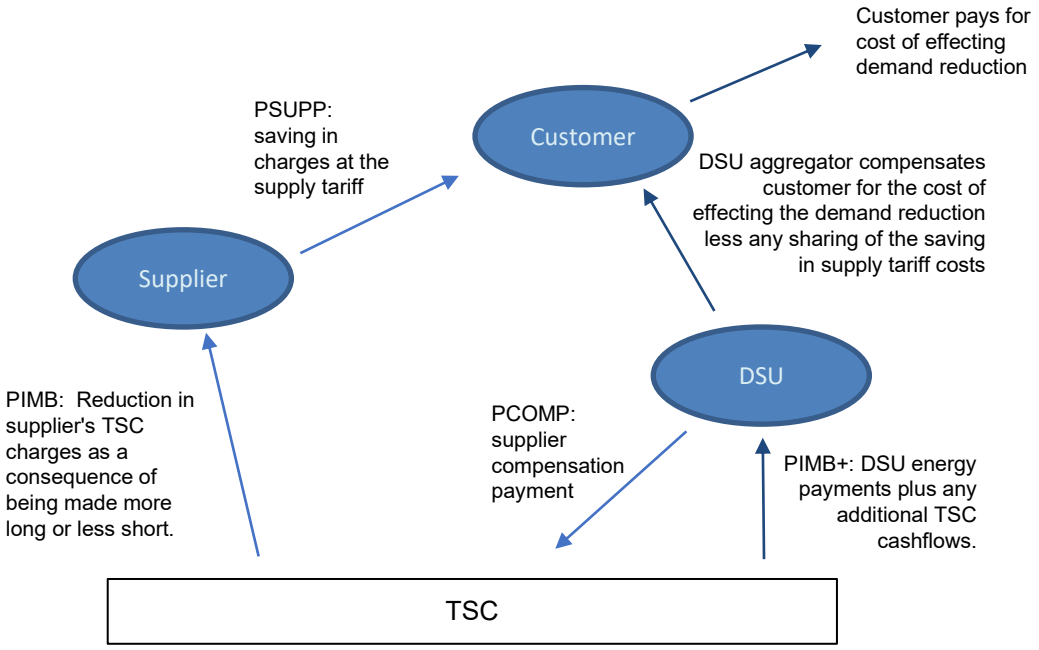

Figure 1: Change in Cashflows in Revised Phase 1 Solution Cashflows for a Demand Reduction

In view of the long timelines associated with implementing perimeter correction but a more pressing need to facilitate energy payments to DSUs, the "Revised Phase 1 Solution" proposes that supplier compensation is paid to *all* suppliers by offsetting the Imperfections Charge charged on all suppliers. In the absence of a system for implementing perimeter correction, the supplier of the demand-reducing customer has its imbalance made more positive, resulting in a credit at the balancing market Imbalance Price (PIMB). Thus, if supplier compensation is paid at a "Supplier Compensation Price" (PCOMP) then the supplier of the demand-reducing customer is compensated at PIMB (rather than PCOMP) with PCOMP being funded by the DSU aggregator and the difference between PIMB and PCOMP being funded through the Imperfections Charge by all suppliers, i.e. including the suppliers without demand-reducing customers as well as those with.

The DSU aggregator is in the same financial position in the Revised Phase 1 Solution as with an explicit system of perimeter correction, while suppliers are in the same position in aggregate. Hence, the SEM Committee's view is that Supplier Compensation Price should be set in the same way in the Revised Phase 1 Solution as it would be with explicit perimeter correction.

2.2. Non-Energy Costs

Without supplier compensation but with a system for perimeter correction, the supplier would wish to bill the customer the same amount as it would have billed had no demand reduction occurred. Thus, if supplier compensation from the DSU aggregator to the supplier is equal to this amount then the supplier, customer and DSU aggregator should be indifferent as to whether the supplier is compensated for the non-consumed energy via the customer or via the market operator. The amount that the supplier would charge the customer would presumably be at the same rate as energy consumed, and determined by the supply tariff agreed between the two. While the terms of the supply agreement may be private, and tailoring supplier compensation to each individual supply agreement impractical, supplier compensation would ideally reflect those costs reflected in the supply tariff.

An alternative formulation is that the supplier compensation is equal to the additional costs that the supplier of the demand-reducing customer would incur were there an explicit system of perimeter correction in place.

As identified in the Proposed Decision Paper, a number of other costs other than energy payments need to be considered, including:

- Imperfections Charges
- Capacity Charges
- Market Operator charges
- Other TSC charges
- System Services Charges
- Network charges
- Hedging costs
- Supplier costs and margin
- Losses
- Taxes and Levies.

2.3. Time-Varying vs Non-Time-Varying

Some costs that might be included - most notably wholesale energy market prices - vary with time. Were the supplier charging the customer on a wholesale market pass-through tariff then a time-varying supplier compensation price would reflect the

hourly or half-hourly variation in costs both for the supplier and the customer. However, supply tariffs are often flat, i.e. non time-varying, in which case time-varying Supplier Compensation Price would likely reintroduce the 'missing money' problem that energy payments to the DSU are intended to prevent[3], and hence would recreate the disincentive to making demand reduction available when it is most needed by the system.

A non-time-varying Supplier Compensation Price would avoid a missing-money problem when the supply tariff also is flat. Were the supply-tariff to be wholesale market pass-through - either fully or partially, say through a time-of-use element – then, as discussed in the Consultation Paper, the DSU aggregator and customer would be over-incentivised to the extent that the customer's saving in the cost of purchasing from the supplier would be greater than the supplier compensation. In 'Model 3'[4], the supplier compensation received by the supplier would be less than the loss in revenue from the customer. However, in the Revised Phase 1 Solution, the supplier is compensated at the Imbalance Price, and hence any loss is borne not by the supplier of the demand-reduction customer but by the Imperfections fund.

Table 1 summarises the interactions between time-of-use/dynamic retail tariffs and Supplier Compensation Price. In the SEM Committee's view, it would be preferable at times of high prices to err on the side of over-incentivising demand reduction where customers have time-of-use or dynamic supply tariffs rather than leaving a missing money problem where supply tariffs are flat. Accordingly, the SEM Committee's view is that a flat Supplier Compensation Price is likely to be most appropriate for the Revised Phase 1 Solution.

[3] In the Consultation Paper and Proposed Decision Paper, the 'missing money' arises where there are no DSU energy payments and a supplier supplies a customer on flat tariff. At times of high wholesale market prices, the savings in the cost of purchasing from the supplier may be insufficient to cover the cost of making demand reductions which would be efficient given the high wholesale market prices. Here, although there are DSU energy payments, the time-varying supplier compensation could be higher than the savings in the cost of purchasing from the supplier, thus creating an equivalent problem.

[4] Model 3 is the cashflow model in the Consultation Paper that has a system of perimeter correction but in which costs of non-consumed energy are recovered from the DSU via the market operator at a Supplier Compensation Price rather than via the customer at the supply tariff.

		Supplier Compensation Price	
		Time-of-Use/Dynamic	**Flat**
Supplier Tariff	**Time-of-Use/Dynamic**	Supplier compensation equals savings in customer savings. **No missing money for DSU.** Principal incentive for demand reduction is from customer's savings, with minimal additional incentive from energy payments.	For demand reduction at times of high wholesale prices, customer savings exceed supplier compensation, in effect the **missing money for DSU is negative.** Excess compensation supplements energy payments, inflating the incentive for demand reduction.
	Flat	For demand reduction at times of high wholesale prices, supplier compensation exceeds customer savings. **Missing money for DSU**. Supplier benefits from inadvertent gain.	For demand reduction at times of high wholesale prices, supplier compensation equals savings in customer savings. **No missing money for DSU.** For supplier: -- with perimeter correction, supplier is financially neutral; -- with Revised Phase 1 Solution, supplier has inadvertent gain, funded by suppliers as a whole via the Imperfections fund.
NB If demand reductions are independent of price, e.g. long-run DSUs, long-term averages of supplier compensation and customer savings match.			

Table 1: Showing interaction of time-of-use/dynamic supply tariffs and Supplier Compensation Price

Note that, for long-run DSUs, all parties should be indifferent regardless of whether supply tariffs and/or the Supplier Compensation Price are flat or time-varying. Given demand reduction is running most or all of the time, any losses any party incurs at certain times are balanced out by gains made at other times.

Although a non-time-varying Supplier Compensation Price seems appropriate, the level will need to be recalculated from time-to-time to ensure the price remains appropriate[5].

[5] In addition to revising the value of Supplier Compensation Price at intervals, the methodology may need to be reviewed from time to time to ensure it remains appropriate following say any change in the structure of other charges, or a significant increase in the use of time-of-use or dynamic tariffs.

2.4. NCDR, the Directive and Amendments to the Electricity Balancing Guidelines

A draft Network Code for Demand Response[6] was presented by ACER to the European Commission in March 2025 and has recently begun comitology. Changes are proposed to Regulation 2017/2195[7] ("the Electricity Balancing Guidelines"), while the Directive 2019/944[8] ("the Directive") has existing provisions relating to demand response. Relevant extracts are shown in Appendix B.

Two mechanisms relating to supplier compensation are proposed:

(i) Art. 17(4) of the Directive allows a system of "*financial compensation*" to parties who are "*directly affected"* by demand response activation. Such financial compensation is limited to the costs the supplier incurs during the demand response activation, while Art. 55A(3) of the EBGL states that it will cover defined costs "*associated with demand response activation*", which may include rebound effects and socialised charges.

(ii) Art. 55A(1) of the EBGL states that a "*financial transfer"* will be calculated where there has been a calculation of a correction to the final position. It requires that the "financial transfer mechanism" won't create undue barriers to aggregators, that it will place appropriate incentives on aggregators and will aim to reflect the cost of energy sourcing.

The legislation – existing and proposed – may thus have a bearing on those costs it is appropriate to reflect in Supplier Compensation Price and those costs it is not.

Art. 17(3) of the Directive states that the regulatory framework must allow aggregators to enter electricity markets without the consent of other market participants. A feature of the Revised Phase 1 Solution and the Supplier Compensation Price is that it does not rely on any form of agreement between suppliers and the DSU aggregator.

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[6] "Recommendation No 01/2025: Network Code on Demand Response", ACER, 7 March 2025.

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

[8] "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.

3. Energy Costs

3.1. Other Markets

A number of international examples were cited in the Consultation Paper, with the SEM Committee's understanding of these arrangements being as follows.

Australia

National Electricity Amendment (Wholesale demand response mechanism) Rule 2020 No. 9[9] stipulates that WDRRR is calculated and published for each quarter starting on the first day of January, April, July or October as "*the peak period load weighted average spot price for each regional reference node over the 12 month period ending immediately before the start of the quarter*" with "*peak periods*" being defined by the Australian Peak Load Electricity Futures Contract[10] as morning peak hours Monday to Sunday.

Belgium

CREG Decision (B)1677[11] defines a "Default Transfer Price". The supplier and the "Flexible Service Provider" are encouraged to negotiate a price and the Default Transfer Price is used in the absence of agreement. The Default Transfer Price is given by:

Default Transfer Price = {0.73 * 1/3 (CAL Y+2 + CAL Y+1 + M+1)
+ 0.27 * EPEXspot BE DAM * 1.05} +/- 5%

where

"CAL Y+2" is the average of daily quotes published by ICE ENDEX during the year two years preceding the year of activation for the baseload product;

[9] "National Electricity Amendment (Wholesale demand response mechanism) Rule 2020 No. 9", Australian Energy Market Commission.

[10] "Australian Peak Load Electricity Futures – Contract Specification", ASX 24 Operating Rules, Australian Securities.

[11] "Décision portant exécution de l'article 19bis, §§ 3 à 5, de la loi du 29 avril 1999 relative à l'organisation du marché de l'électricité, en vue de rendre possible le transfert d'énergie", Decisoin (B)1677, CREG, 15 March 2018.

"CAL Y+1" is the average of daily quotes published by ICE ENDEX during the year preceding the year of activation for the baseload product;

"M+1" is the average of daily quotes published by ICE ENDEX during the month preceding the month of activation for the baseload product; and

"EPEXspot BE DAM" is the EPEX spot Belgium on the day ahead market for the hour during which activation of demand reduction occurs.

The SEM Committee's understanding is that the factor of 1.05 is an explicit allowance for the supplier's margin, while the adjustment of +/-5% is used to increase the price for downward activations and decrease the price for upward activations to account for "diversity of electricity sales prices to end consumers" and encourage the negotiated solutions that are preferred in the CREG Decision.

Britain

Following Modification P415, the Balancing & Settlement Code[12] provides for a "Supplier Compensation Reference Price" which is the default retail tariff cap set by Ofgem. It also provides for a "Supplier Compensation Reference Price Methodology Document" to be established and maintained by the industry BSC Panel.

The Ofgem default retail tariff cap is based on a methodology recommended by the Competition and Markets Authority in energy market investigation[13]. The methodology produces an overall customer tariff, although individual components, including a wholesale market cost, are identified. The methodology was initially updated every six months – now three months - by calculating an average over six months of forward contract prices covering a year. Forward contract prices are provided by ICIS.

[12] "Balancing and Settlement Code, Section T", V45.0, Elexon.

[13] "Energy Market Investigation Final Report", Competition and Market Authority, 24 June 2016.

France

The Notification d'Echange de Blocs d'Effacement ("NEBEF") arrangements in the French market have recently been superceded by Notification d'Echange de Blocs de Consommation ("NEBCO"). Under Articles L.271-3 and R.271-8 of the French Energy Code[14], and Chapter 5 of the Règles de Marché[15], demand response aggregators pay compensation to electricity suppliers affected by demand response activation.

The SEM Committee's understanding is that a compensation price is calculated for a year N as the sum of an energy price and a capacity price. The energy price is calculated as an average of the price of EEX French Financial Power Futures annual peak-load forward products for year N, averaged for each day over the preceding year but one. Prices are calculated for summer and winter and peak and off-peak hours. The capacity price is based on the average of capacity auction prices over the two years preceding the delivery year.

3.2. Options for SEM

The arrangements in Britain, Belgium and France rely on the availability of price indices for traded forward contracts, with the British arrangements relying on data from ICIS, Belgium from ICE and France from EEX. In contrast, Australia uses an average of peak spot prices, while the formula for Belgium is based partially on spot prices. While any price data for a preceding period may lose relevance as market conditions change, the benefit of using forward contract prices is that they will nevertheless reflect expectations for the upcoming period, rather than the expectations or actual prices from the preceding period. Moreover, even if market conditions do change, the previous (rather than current) expectation of prices may actually better represent the expectations on which commercial terms were set between the supplier and the customer.

In the SEM, trading of forwards contracts takes place on platforms such as Tullett Prebon and Marex Spectron. However, the SEM Committee understands that liquidity is limited and is insufficient to provide a reliable index of forward prices. One

[14] "Code de l'Energie", Institut Francais d'Information Juridique, 2 April 2026.

[15] "Règles de Marché Chapitre 5: NEBCO", RTE, 1 September 2025.

option might thus be to use Directed Contracts[16,17] (DC). A mixture of baseload, mid-merit and peaking prices might best represent the energy cost for all customers but the baseload price alone might better represent the energy cost associated with supplying demand-reducing customers. DC regression formulae could be used to update prices for the relevant DC products for each day over a defined averaging period. Given the DC regression formulae are linear, it would make no difference whether the formulae were applied to each day and the resulting prices averaged or whether the commodity prices were averaged and the formulae applied to these averages. It is possible that the 'volatility window' for the formulae could be exceeded during this averaging period, giving the option of treating these data as outliers or continuing to apply the formulae unless say the averaged commodity prices exceeded the volatility window.

Given that DC prices and formulae are determined every quarter, there is the option to update the Supplier Compensation Price every quarter or to update biannually or annually. If the price were updated say every quarter, the option would exist to calculate either

(a) a price from the relevant DC product price for the relevant quarter, recognising that this price would show seasonal variation; or

(b) a price from the average of the relevant DC product price for four consecutive quarters, in order to eliminate seasonal effects.

An advantage of using DC prices and formulae is they are already accepted for use in SEM arrangements.

In the absence of other reliable indices, another approach would be to use historical spot prices. Considerations under this approach include:

- choice of market: Imbalance Price or day-ahead market;
- observation period for which the average is calculated;
- frequency of updating;

[16] "Directed Contracts Implementation Paper Consultation Paper", SEM-17-064, 4 September 2017.

[17] "Directed Contracts Implementation Decision Paper", SEM-17-081, 15 November 2017.

- assessment period between the end of the observation period and the period to which the Supplier Compensation Price is to apply; and
- weighting.

Imbalance Price vs Day-Ahead Market Price

In principle the day-ahead market price will reflect the expectation of Imbalance Prices. The SEM Committee understands that there may be effects resulting from the lack of market coupling in some markets but not in others, although assetless trading should mitigate these effects. To the extent that there are systematic differences, the SEM Committee's understanding is that the Day Ahead Market price is likely to better reflect the basis on which suppliers supply their customers given the high volumes traded in this market, and hence may be more appropriate for determining Supplier Compensation Price.

Observation Period

Averaging over a year avoids seasonal effects but leads to a relatively long time between the beginning of the averaging period and the end of the period for which a Supplier Compensation Price is being calculated. Conversely, shorter averaging periods will reduce the lag but introduce seasonality. In the SEM Committee's view, seasonal variations in prices may have a similar effect to time-of-use or dynamic prices. Thus, whether seasonality in Supplier Compensation Prices is appropriate will depend on whether it better or worse reflects typical commercial arrangements between suppliers and demand-reducing customers.

Frequency of Update

In principle, the frequency of update is independent from the averaging period, such that it would be theoretically possible to have a rolling one year averaging period updated every settlement period. That said, it would not seem to make sense to have a short averaging period, e.g. a week, but infrequent updating, e.g. annually. Thus, in the SEM Committee's view the averaging period should be established first, which then places a minimum on the updating frequency. Possible options include:

Averaging Period	Frequency of Updating
12 months	12, 6 or 3 months
6 months	6 or 3 months
3 months	3 months or 1 month
1 month	1 month

A long averaging period and frequency of updating would minimise the administrative overhead and, as discussed, a long averaging period may be desirable to eliminate seasonal variations, if that is appropriate. On the other hand, a long averaging period means that the price is set using older, and thus potentially less relevant, data. The SEM Committee would welcome views.

Assessment Period

There needs to be an assessment period between the end of the averaging period over which price data is observed and the start of the period to which the Supplier Compensation Price applies in order to undertake the necessary calculations. There could also be additional requirements such as publishing prices in advance of the period to which they apply. While giving more notice of the Supplier Compensation Price could have benefits, a disadvantage of a longer assessment period would be that it may reduce the relevance of the observed data to the period to which the Supplier Compensation Price applies.

Weighting

Prices can be weighted in various ways. Possible options would be:

(i) Weighting towards more recent prices on the basis that recent prices are more relevant. This would tend to reduce the lag effect in a similar manner to shortening the averaging window. However, like a shorter averaging window, it would have the effect of introducing or amplifying seasonality.

(ii) Weighting by system demand, making the average price more representative of the energy cost for the average customer of the system as a whole. However, the weighted average might not be more representative of a typical demand-reduction customer.

In the absence of evidence to the contrary, the SEM Committee's view would be that no weighting, i.e. a straight arithmetic average, would be most appropriate. However, the SEM Committee would welcome views.

4. Other Costs

4.1. Imperfections Charges

The Imperfections Charge is charged on demand, calculated as the Imperfections Price (PIMP) multiplied by the Loss-Adjusted Metered Quantity[18] (QMLF). Hence, were an explicit system of perimeter correction implemented then the supplier of a demand-reducing customer would incur additional cost as a result of the perimeter correction, which it would look to either recover from the customer or look to be compensated for by the aggregator. Thus, the SEM Committee's view is that the PIMP should be included in determining the Supplier Compensation Price.

4.2. Capacity Charges

The Capacity Charge is charged on demand, calculated as the Supplier Capacity Charge Price (PCCSUP) multiplied by QMLF, as with Imperfections, but multiplied also by a Capacity Charge Metered Quantity Factor (FQMCC) which is one during daytime hours and zero at other times.

The SEM Committee's view is that PCCSUP should be included in determining the Supplier Compensation Price. Whether FQMCC should be included depends on whether supply tariffs better reflect both daytime and night prices or just daytime prices.

4.3. Market Operator Charges

The Variable Market Operator Charge (CVMO) is charged on demand, calculated as the Variable Market Operator Price (PVMO) multiplied by QMLF, as with Imperfections. Thus, the SEM Committee's view is that PVMO should be included in determining the Supplier Compensation Price.

4.4. Other TSC Charges

Under the TSC, suppliers are liable also for the Residual Error Volume Charge and the Currency Adjustment Charge, calculated as QMLF multiplied by the Residual Error Volume Price (PREV) and Currency Cost Price (PCC) respectively.

[18] Subject to perimeter correction, as discussed in Section 2.1.

The Residual Error Volume Price depends also on a Non-Interval Energy Proportion (FNIEP), which the SEM Committee considers is almost certainly zero for demand reduction customers, and the Residual Meter Volume Interval Proportion (RMVIP) for the relevant jurisdiction. Accordingly, the Supplier Compensation Price should include RMVIP multiplied by PREV. Typical values of PREV are relatively small – the value for 2025/26 is €0.46/MWh[19] – so the SEM Committee considers that a demand-weighted average for the two jurisdictions would be acceptable if there are no other reasons for jurisdictionally-specific Supplier Compensation Prices.

As such, the SEM Committee's view is that both PREV and PCC should be included in determining the Supplier Compensation Price. That said, the current value of RMVIP is zero so the issue of PREV, jurisdictionally-specific or otherwise, currently does not arise.

4.5. System Services Charges

System Services charges currently are levied under the TSOs' Statement of Charges, prior to the introduction of a System Services Code[20]. Under these Statements of Charges, System Services charges are levied on a per MWh basis and under the current proposals for the System Services Code it is anticipated that a per MWh charge will continue using QMLF as defined in the TSC.

While the demand side is an important provider of system services, it's unclear whether demand side providers receiving system services revenues will benefit a second time, i.e. double counting, from reductions in system services charges. On the other hand, a supplier charging a customer for non-consumed energy at its normal commercial rates would recover a contribution towards system services charges and would presumably have agreed its terms with the customer on that expectation, while suppliers would also incur a cost were a system of perimeter correction implemented. Indifference between recovery via the market operator as opposed to via the customer, as discussed in Section 2.2, suggests that the Supplier Compensation Price should include an allowance for System Services charges.

[19] "Single Electricity Market MO Tariffs and Charges and Imperfections Charge, 01 October 2025 – 30 September 2026", SEMO, 2 September 2025.

[20] "System Services Code Development Plain English Version" Version 3.0, EirGrid & SONI, October 2025.

Under the TSOs' Statements of Charges the question arises, as with PREV (see Section 4.4 above), whether any allowance for System Services charges should be jurisdictionally specific. As currently proposed, under the System Services Code, the System Services Charge would be an all-island charge and so the issue would not arise.

Lastly, noting that the System Services Code will be distinct from the TSC, it could be argued that any allowance for the System Services Charge ought to be embodied in a supplier compensation mechanism which is specific to the System Services Code, rather than being included in the TSC. However, the SEM Committee's view is that inclusion in the TSC Supplier Compensation Price would be more expedient.

4.6. Network Charges

The SEM Committee's view is that similar principles will apply to network charges as to System Services Charges.

As with System Services Charges, network charges are separate from the TSC and levied under the TSOs' Statements of Charges, although, unlike System Services, there is no proposal of which the SEM Committee is aware that could result in network charges being subject to perimeter correction. And while there is no obvious revenue stream for demand reduction which, taken along with reductions in demand network charges, could result in double counting, a supplier charging a customer for non-consumed energy at its normal commercial rates would recover a contribution towards network charges.

Hence it's unclear whether the Supplier Compensation Price should include an allowance for network charges although, again, indifference between recovery via the market operator as opposed to via the customer, as discussed in Section 2.2, suggests that it should. Moreover, network charges vary between different classes of customer, requiring any allowance to be based either on one particular customer class or on a composite of more than one customer class. Lastly, network charges are jurisdictionally specific raising the question of whether the Supplier Compensation Price should be jurisdictionally specific to reflect this.

4.7. Hedging Costs

Considering the supplier's hedging costs then either:

(i) if a demand reduction is not or cannot be anticipated then clearly the supplier will not adjust its hedging strategy; or

(ii) if a demand reduction can be and is anticipated then the supplier could adjust its strategy (and hence costs) to hedge only the reduced demand and not the non-consumed energy. However, if explicit perimeter correction could be applied and the supplier required to purchase the non-consumed then it seems likely that the supplier would wish to hedge the non-consumed energy also.

Hence, in each case, it seems appropriate to include in the Supplier Compensation Price an allowance for hedging costs.

What is less clear is how an appropriate hedging cost can be quantified. For the GB Supplier Compensation Reference Price an allowance of 0.2% is included for "*rehedging day ahead*"[21] and an "*additional risk allowance*" of 1%, while for the Belgian default transfer price, no explicit hedging allowance is included. However, in both cases hedging is implicit in the use of forward contract prices in calculating the reference price. The SEM Committee would welcome views on whether it is appropriate to include allowance for hedging costs in the Supplier Compensation Price and, if so, how the size of any such allowance should be determined.

4.8. Supplier Costs and Margins

Suppliers incur internal costs in running their businesses and need also to make a margin, both of which are recovered through sales of electricity to customers. In the event that demand reduction is activated, suppliers no longer recover these costs and margin on non-consumed energy, while the costs and margin are unchanged. Were an explicit system of perimeter correction in place and were the supplier to recover the cost of the non-consumed energy through charges billed to the customer then the supplier would be able to recover these costs and margin. Hence, if the aggregator and supplier are to be indifferent between supplier compensation being made directly (i.e. via the market operator) or via the customer then an allowance

[21] See Supply Licence Condition 28AD, Annex 2.

should be included in the Supplier Compensation Price. However, regardless of any rationale, there is a question of consistency with EU legislation. In particular, it may be inconsistent with the requirement in the Directive for "*financial compensation*" that it "*shall be strictly limited to covering the resulting costs incurred ... during the activation of demand response*", although consistent with the requirement in the Regulation that *"market rules deliver appropriate investment incentives for demand response"* and the requirement in the proposed amended Electricity Balancing Guidelines applying to "*financial transfers*" that they "*shall place appropriate incentives on market participants engaged in aggregation*".

The SEM Committee notes the Belgian Default Transfer Price includes an allowance for supplier margin.

4.9. Losses

In the Trading and Settlement Code, transmission losses are accounted for by the application of Transmission Loss Adjustment Factors by SEMO and of Distribution Loss Adjustment Factors by the Meter Data Provider. The SEM Committee's view is thus that no explicit allowance is required for transmission and distribution losses, and that it is necessary only that the Supplier Compensation Price is determined and applied with reference to appropriately loss-adjusted quantities.

4.10. Taxes and Levies

All payments and charges calculated under the Trading and Settlement Code are calculated exclusive of VAT. Thus, the SEM Committee's initial view is that cashflows and changes in cashflows calculated by reference to the Supplier Compensation Price will be subject to the same tax treatment as other settlement cashflows and that, as a result, it may not be necessary to make explicit allowance for VAT in the Supplier Compensation Price.

The PSO Order requires suppliers to charge the PSO Levy on final customers. The Levy rates are per customer for accounts designated as Domestic or Small, and per kVA of the Maximum Import Capacity for accounts designated as Medium/Large. Hence, PSO Levy charges will be unaffected by demand reductions and the SEM Committee's view is that no allowance in the Supplier Compensation Price is appropriate.

5. Views Invited and Next Steps

The SEM Committee welcomes views on the matters discussed in this paper and, in particular, on the questions listed in Appendix A.

The SEM Committee invites views from all stakeholders on the discussion and issues raised in this consultation paper. In particular, it welcomes views on the questions listed in Appendix A plus any other issues stakeholders may consider relevant.

Responses to this consultation paper should be sent to tsc@cru.ie and tsc@uregni.gov.uk, by close of business on 10 July 2026. 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 be 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. If possible, confidential information should be contained in a separate appendix 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 on the matters in this consultation and the ratification of the proposed decisions in the Proposed Decision Paper.

Appendix A: Consultation Questions

Re Section 2

Q1: Do you agree with the SEM Committee's analysis in Section 2? In particular, do you agree that it is appropriate to set the Supplier Compensation Price for the Revised Phase 1 Solution in the same way it would be set were there a system of perimeter correction? Do you agree that an appropriate objective is that suppliers and the DSU aggregator should be indifferent whether compensation is made via the customer or the market operator? Please explain your views.

Q2 Do you consider that supply agreements between suppliers and demand reduction customers typically involve a fixed price or are they likely to incorporate dynamic or time-of-use pricing? Are there other terms and conditions of these agreements that may be relevant? Please provide as much explanation and detail as possible.

Q3 Do you agree that it is appropriate that the Supplier Compensation Price is fixed, with no dynamic or time-of-use element? Please explain your views.

Re Section 3

Q4 Do you agree with the SEM Committee's understanding of how reference prices for supplier compensation are determined in electricity markets other than SEM? Please explain your views.

Q5 Would Directed Contract prices and formulae be suitable for determining the energy cost component of the Supplier Compensation Price? If so, would a mixture of Directed Contract prices be appropriate or should the Supplier Compensation Price be based on the price of just baseload contracts? How should the process of observing commodity prices and calculating an averaged DC product price work? Please explain your views.

Q6 Do you agree that the trading of forward contracts is currently not sufficient to provide a suitable basis for determining Supplier Compensation Price? Please explain your views.

Q7 Would an average of historic market prices be suitable? Would Day Ahead Market prices or Imbalance Prices be most appropriate? Would these be preferable to the prices of Directed Contracts? If so, over what period should prices be averaged? What would be a suitable assessment period for calculation and publication of Suppler Compensation Price? Do you agree that no weighting would be necessary when averaging DAM or Imbalance Prices? Please explain your views.

Q8 How often should the Supplier Compensation Price be updated? Please explain your views.

Re Section 4

Q9 Do you agree that, in addition to energy, the Supplier Compensation Price should reflect the Imperfections Price (PIMP)? Please explain your views.

Q10 Do you agree that the Supplier Compensation Price should reflect the Supplier Capacity Charge Price (PCCSUPP). Should it also take into account the Capacity Charge Metered Quantity Factor (FQMCC)? Please explain your views.

Q11 Do you agree that the Supplier Compensation Price should reflect the Variable Market Operator Price (PVMO)? Please explain your views.

Q12 Do you agree that the Supplier Compensation Price should reflect the Residual Error Volume Price (PREV), the Non-Interval Energy Proportion (RMVIP) and Currency Cost Price (PCC)? Given the Non-Interval Energy Proportion is jurisdictionally specific, do you consider it necessary, if only (given that RMVIP is currently zero) in principle, to have a jurisdictionally-specific Supplier Compensation Price? Please explain your views.

Q13 Do you agree that the Supplier Compensation Price should reflect the System Services Charge price? Please explain your views.

Q14 Do you agree that the Supplier Compensation Price should reflect network charges? Given network charges differ for different classes of customers, which would it be most appropriate to use in determining the Supplier Compensation Price? And given network charges are jurisdictionally specific,

do you consider that these make it necessary to have a jurisdictionally-specific Supplier Compensation Price? Please explain your views.

Q15 Do you agree that the Supplier Compensation Price should reflect hedging costs? If so, how should the allowance for these costs be determined? Please explain your views.

Q16 Do you agree that the Supplier Compensation Price should reflect supplier internal costs and margin? If so, how should the allowance for these costs be determined? Please explain your views.

Q17 Do you agree that no explicit allowance is required for losses, and that losses are implicitly allowed for in the loss-adjustment of other quantities? Please explain your views.

Q18 Do you agree that no explicit allowance is required for taxes? Please explain your views.

Q19 Do you agree that no explicit allowance is required for the PSO Levy? Please explain your views.

Q20 Are there any other costs that should be taken into account? Please explain your views.

Appendix B: Extracts from Existing and Proposed Legislation

Existing Directive 2019/944 (Common Rules for the Internal Market for Electricity)

Article 17: 'Demand response through aggregation

3. *Member States shall ensure that their relevant regulatory framework contains at least the following elements:*

   (a) the right for each market participant engaged in aggregation, including independent aggregators, to enter electricity markets without the consent of other market participants; ...

   (d) an obligation on market participants engaged in aggregation to be financially responsible for the imbalances that they cause in the electricity system; ...

4. *Member States may require electricity undertakings ... to pay financial compensation to other market participants ..., if those market participants ... are directly affected by demand response activation. ... In such cases, the financial compensation shall be strictly limited to covering the resulting costs incurred by the suppliers of participating customers ... during the activation of demand response.*

Proposed Amended Regulation 2017/2195 (Electricity Balancing Guidelines)

Article 52: Imbalance Settlement

2. *By one year after entry into force of this Regulation, all TSOs shall develop a proposal to further specify and harmonise at least: (a)the calculation of an imbalance adjustment pursuant to Article 54 and the calculation of a position, an imbalance and an allocated volume , including the cases of balance responsible parties engaged in aggregation, for each of the implemented aggregation models, with the calculation of the corrections, the financial transfer – if required – and the financial compensation, – if implemented;*

Article 54: Imbalance Calculation

1. Each TSO shall calculate within its scheduling area or scheduling areas when appropriate the final position, the allocated volume, the imbalance adjustment and the imbalance:

(a) for each balance responsible party;

(b) for each imbalance settlement period;

(c) in each imbalance area.

4. Each TSO shall set up the rules for:

(a) the calculation of the final position;

(a1) the calculation of a correction of the final position, if applicable, for the cases of multiple balance responsible parties at the same metering point, when at least one of them is engaged in aggregation;

(b)the determination of the allocated volume;

(b1) the determination of a correction of the allocated volume, if applicable, for the cases of multiple balance responsible parties at the same metering point, when at least one of them is engaged in aggregation;

(c) the determination of the imbalance adjustment pursuant to paragraph 5a;

(d) the calculation of the imbalance;

(e) claiming the recalculation of the imbalance by a balance responsible party.

Article 55A: Financial transfer and compensation

1. Each TSO shall calculate for each imbalance settlement period, for each imbalance area, a financial transfer for each balance responsible party for which a correction in the final position has been calculated pursuant to Article 54(4)(1a). The calculation method of the financial transfer shall be based on a formula, included in the national terms and conditions for balance responsible parties pursuant to Article 18(6)(f). The financial transfer mechanism shall not create undue barriers to market entry for market participants engaged in aggregation,

shall place appropriate incentives on market participants engaged in aggregation, and shall aim to reflect the cost for energy sourcing within the relevant energy transfer."

2. *If the Member State has established financial compensation pursuant to Article 17(4) of Directive 2019/944/EU, each TSO shall calculate this financial compensation for the relevant market participants or for the market participants' balance responsible parties affected by demand response activation.*"

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

   (a) encompass the reimbursement of defined costs associated with demand response activation, which costs may include, but are not limited to, costs due to the rebound effect and costs of socialised charges which increase due to demand response activation, and which are not already covered by the financial transfer pursuant to paragraph 1.

Appendix C: Relevant Documents

1. "*Demand Side Units: A Revised Phase 1 Solution for Energy Payments and Other Issues: Consultation Paper*" SEM-24-046, 23 August 2024.
2. "*Demand Side Units: A Revised Phase 1 Solution for Energy Payments and Other Issues: Proposed Decision Paper*", SEM-26-017, 31 March 2026.
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. "*Recommendation No 01/2025: Network Code on Demand Response*", ACER, 7 March 2025.
6. "*National Electricity Amendment (Wholesale demand response mechanism) Rule 2020 No. 9*", Australian Energy Market Commission, 11 June 2020.
7. "*Australian Peak Load Electricity Futures – Contract Specification*", ASX 24 Operating Rules, Australian Securities.
8. "*Décision portant exécution de l'article 19bis, §§ 3 à 5, de la loi du 29 avril 1999 relative à l'organisation du marché de l'électricité, en vue de rendre possible le transfert d'énergie*", Décision (B)1677, CREG, 15 March 2018.
9. "*Code de l'Energie*", Institut Francais d'Information Juridique, 2 April 2026.
10. "*Règles de Marché Chapitre 5: NEBCO*", RTE, 1 September 2025.
11. "*Balancing and Settlement Code, Section T*", V45.0, Elexon, 27 November 2025.
12. "*Standard conditions of electricity supply licence, Condition 28AD*", Ofgem.
13. "*Energy market investigation Final report*", Competition and Markets Authority, 24 June 2016.
14. "*Directed Contracts Implementation Paper Consultation Paper*", SEM-17-064, 4 September 2017
15. "*Directed Contracts Implementation Decision Paper*", SEM-17-081, 15 November 2017.
16. "System Services Code Development Plain English Version" Version 3.0, EirGrid & SONI, October 2025.