# Applicability of Reliability Option Non-performance Difference Charges to Available In-Merit Units

**SEM-22-030**

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# EXECUTIVE SUMMARY

Participants that are successful in a Capacity Auction become the holders of a “Reliability Option” (RO). The RO creates an incentive to deliver energy by exposing Capacity Market Units to Difference Charges when energy prices exceed the Strike Price of the RO. These circumstances are referred to as “RO events”.

Since I-SEM go-live, there have been multiple RO events. The SEM Committee understands that, during these events, Capacity Market Units have been declared available, and been in-merit, but have not been dispatched. These units are exposed to Non-performance Difference Charges and in some instances, disputes have been raised as a result. A series of modifications to the Trading and Settlement Code have also been proposed, which have sought to limit the applicability of these charges in these circumstances.

The possibility of removing Non-performance Difference Charges where operational constraints are binding and prevent the dispatch of a Capacity Market Unit was originally consulted on by the SEM Committee in SEM-19-024. It was decided in SEM-19-054 not to implement this change at that time, but to keep the situation under review to allow for additional operational experience to be gathered, and to better understand how certain changes made to the Balancing Market may impact on this area. The SEM Committee is of the view that, given the additional operational experience in the market since the matter was first consulted on, it is now an appropriate time to give further consideration to the issue.

In SEM-21-042, the SEM Committee has also examined the operation of Administered Scarcity Pricing, which was implemented in the SEM to ensure that prices rise appropriately to reflect scarcity, but which has not been triggered since go-live. While no change to Administered Scarcity Pricing was made at that time given, in particular, the practical difficulty of implementing any such changes in time to be effective for the immediate Winter period, the SEM Committee was of the view that the interaction between Administered Scarcity Pricing, the RO Strike Price and prices in the ex-ante and balancing markets during periods of tight generation capacity margins was an area which merited further consideration in the future.

Following the outcome of this consultation on the applicability of Non-performance Difference Charges to available in-merit generators, it is the SEM Committee's intention to re-examine the related area of the operation of the Administered Scarcity Pricing mechanism.

This paper requests feedback from the TSOs and from stakeholders regarding the circumstances in which Capacity Market Units can be available and in-merit, but not dispatched. The paper also seeks views on a number of different approaches to the application of Non-performance Difference Charges to such units, and requests stakeholders' views on these approaches, or others that they may identify.

## Table of Contents

## Glossary of Terms and Abbreviations

| Abbreviation or Term | Definition or Meaning |
|---|---|
| CMU | Capacity Market Unit |
| CRM | Capacity Remuneration Mechanism |
| I-SEM | Integrated Single Electricity Market |
| RAs | Regulatory Authorities |
| RO | Reliability Option |
| TSC | Trading and Settlement Code |

# 1. Introduction

## 1.1. Capacity Remuneration Mechanism (CRM)

The Capacity Remuneration Mechanism (CRM) was introduced as part of the I-SEM market arrangements which went live on 01 October 2018. The CRM provides remuneration through monthly Capacity Payments to Capacity Market Units (CMUs) that are successful in competitive Capacity Auctions. Capacity Auctions are held four years in advance of a Capacity Year, with additional auctions for incremental capacity held, if needed, closer to the Capacity Year. The funds to make Capacity Payments are recovered from suppliers through Capacity Charges. An availability incentive mechanism is also included in the CRM through the implementation of Reliability Options. More detailed information on the design of the CRM can be found in the relevant SEM Committee decision papers[1].

Under the design of the CRM, participants that are successful in a Capacity Auction and therefore are the holder of a capacity contract must take on a “Reliability Option” (RO). An RO is a one-way Contract for Difference that is settled by reference to the RO Strike Price. Difference Charges are levied on Capacity Market Units based on the difference between the Market Reference Price and the RO Strike Price. The money recovered from Difference Charges is then paid to Suppliers through Difference Payments, also based on the difference between the Market Reference Price and the RO Strike Price. Difference Payments effectively act as a hedge for suppliers across all market timeframes at the level of the RO Strike Price.

Difference Charges under the RO are calculated based on the market in which power was first sold. The Market Reference Price can therefore be the Day-ahead Trade price, the relevant Intra Day Trade price or the relevant Balancing Trade Price in the case of a Balancing Market action. If, however, the RO holder’s power is not bought in the ex-ante markets or as a Balancing Market action, the Market Reference Price is set to the Imbalance Settlement Price, and the RO holder must pay Non-performance Difference Charges if the Imbalance Settlement Price exceeds the RO Strike Price. The treatment is similar for Suppliers, in that they will receive

[1] SEM-15-103, SEM-16-022 & SEM-16-039.

Difference Payments based on the Market Reference Price in the market in which the power was first purchased.

The CRM design also includes a Socialisation Fund to cover any shortfall between Difference Charges and Difference Payments. Such shortfalls may arise if Stop Loss Limits are applied or where some capacity does not hold an RO, e.g. capacity that does not hold a capacity contract or the de-rated portion of a Capacity Market Unit's total capacity. The Socialisation Fund is drawn from Suppliers through the Difference Payment Socialisation Charge. Any over-recovery of charges may also be collected into the Socialisation Fund. No additional money is being drawn from suppliers in the 2021/22 tariff year[2] as the balance in the fund at the time the tariffs were set was significantly higher than the level of €15 million, which is considered adequate. The current balance of the Socialisation Fund remains well above this level, at €20.2m (as of April 2022).

Another aspect of the CRM design is Stop-Loss Limits. Stop-Loss Limits are an annual limit and billing period limit on the amount of Non-performance Difference Charges that can accrue for a Capacity Market Unit. The annual limit is based on a multiple of annual forecast and actual Capacity Payment revenue. The annual limit multiplier is currently set at 1.5, meaning that the maximum Non-performance Difference Charge a Capacity Market Unit could incur in a year is 1.5 times its Capacity Payment revenue. There is also a Billing Period Stop-Loss Limit to ensure that the reliability incentive is not removed for the whole year in one single event. The Billing Period Stop-Loss Limit multiplier is currently set at 0.5.

The RO Strike Price is a floating price and is updated monthly in accordance with the formula contained in section F.16 of Part B of the Trading and Settlement Code (TSC). This formula bases the Strike Price on the cost of a hypothetical low efficiency peaking unit and includes a floor at the price of a theoretical demand side unit. The cost of the hypothetical low efficiency peaking unit is determined as the maximum of the fuel and carbon costs of either a natural gas-fired unit or an oil-fired unit, assuming a certain efficiency.

[2] https://www.semcommittee.com/sites/semc/files/media-files/SEM-21-063%20ISEM%20Parameters%202021-22.pdf

## 1.2. RO Difference Charges

Section F.18 of the Trading and Settlement Code Part B details the calculation of Difference Charges on Capacity Market Units. The algebra in the Trading and Settlement code ensures that Difference Charges will only be applied in the market timeframe in which the quantity was first traded.

Difference Charges apply when the Market Reference Price exceeds the Strike Price. Where a Capacity Market Unit is generating, or is traded, in line with its capacity market obligations, revenue will be earned from the market to “cover” these Difference Charges. If a Capacity Market Unit is sold in the ex-ante markets up to its Obligated Capacity Quantity but then does not generate, it will be subject to imbalance charges at the Imbalance Settlement Price. This gives RO holders the incentive to not only trade Obligated Capacity Quantities but then go on to physically deliver them. However, where a Capacity Market Unit is not running, and has not traded, in line with its Capacity Market obligations, revenue will not be earned from the market to cover the Difference Charges. These are called Non-performance Difference Charges.

Non-performance Difference Charges are calculated separately to Difference Charges within the Trading and Settlement Code. However, the code algebra ensures that Non-performance Difference Charges only apply when it is deemed that the Capacity Market Unit has not delivered its Obligated Capacity Quantity. The Non-performance Difference Quantity is the difference between the Obligated Capacity Quantity and the Tracked Difference Quantity, where the Tracked Difference Quantity is below the Obligated Capacity Quantity. The Tracked Difference Quantity is the sum of the Day-ahead and Within-day[3] quantities. The tracking variables used in the Trading and Settlement Code algebra thus ensure Difference Charges are not levied on the same quantity more than once notwithstanding that that quantity may have been traded multiple times across the different market timeframes.

However, the tracking quantities also include any quantity used for system services that is deemed to count towards capacity obligations as set out in section F.18.6 of the TSC. In TSC Appendix N: “Flagging and Tagging”, a System Service Flag is set where a Generator Unit’s scheduled output is bound by the presence of an

[3] Within-day Trade Quantities include Intraday Trade Quantities and Balancing Trade Quantities.

Operational Constraint relating to the provision of Replacement Reserve. Thus, any quantity, which is not traded or physically delivered as a result of providing Replacement Reserve, is nevertheless counted towards meeting the Obligated Capacity Quantity, and hence exempted from Difference Charges.

The CRM Detailed Design (SEM-19-103) considered that a broader set of system services could contribute towards meeting a unit's capacity obligations. That decision paper noted that capacity providers who are directed by the TSO to provide "operating reserve or other DS3 system services" would not be "inappropriately disadvantaged" when acting on such instructions. Therefore, the System Service Flag was devised to facilitate the contribution of such services towards capacity obligations. As implemented currently, the System Service Flag only applies to capacity bound by an Operational Constraint related to the provision of Replacement Reserve.

Thus, while the principle underpinning the design of the CRM is that exposure to Non-performance Difference Charges is linked to actual volumes traded or delivered, rather than to unit availability, an exception is made where the System Service Flag is set for a unit.

## 2. Background to the Consultation

### 2.1. RO Events since I-SEM Go-Live

Since I-SEM Go-Live, there have been a total of 20 Imbalance Settlement Periods, across 9 different days[4], in which the Market Reference Price exceeded the Strike Price. The total materiality of the resulting Non-performance Difference Charges has been €10.7m.

Over the course of these RO events since I-SEM Go-Live, the RAs understand that there have been Capacity Market Units, which have been declared available and been in-merit[5], but which have not been dispatched for a variety of reasons and have been exposed to Non-performance Difference Charges as a result. This has led to a number of disputes being raised and of Trading and Settlement Code modifications

[4] This does not include the RO events, or Non-performance Difference Charges that were not invoiced, in September 2021.

[5] Throughout this paper, in-merit is intended to mean relative to the price in the Balancing Market.

being proposed that have sought to limit the applicability of Non-performance Difference Charges in circumstances where units are available but not dispatched. Other modification proposals have been raised to remove certain constraints and TSO actions from the imbalance pricing process, such that these constraints and actions cannot trigger an RO event. Further detail on these modification proposals is provided in Section 2.3.

### 2.2. Balancing Market and Capacity Market Options Paper

After I-SEM Go-Live, the performance of the Balancing Market provided some cause for concern. Specifically, extremely high prices in January 2019 as a result of the North-South Tie Line constraint were a cause for particular concern. Mod_09_19 '*Removal of Locational Constraints from Imbalance Pricing Calculation*' removed this constraint from the imbalance pricing process.

Following the implementation of Mod_09_19 on 2 May 2019, the SEM Committee consulted on two further options for potential changes to the Balancing Market design in SEM-19-024[6]. Option 1 involved removing all constraints from the imbalance pricing process through what is known as Simple NIV tagging. Option 2 looked at removing the exposure to Difference Charges for those units which were available to deliver but could not be dispatched up to meet their RO obligation due to a set of binding Operational Constraints. The list of applicable constraints proposed in that paper were:

- All Operating and Replacement Reserves (except Negative Reserves) – currently Replacement Reserve only;
- S_MWR_ROI, and S_MWR_NI – when transfers from Ireland to Northern Ireland and vice versa are at a maximum;
- S_SNSP_TOT – when the System Non-Synchronous Penetration (SNSP) level is equal to the SNSP limit;
- S_RoCoF – ensures Ireland and NI power systems do not exceed Rate of Change of Frequency (RoCoF) limits;

[6] SEM-19-024 Balancing Market and Capacity Market Options Consultation Paper

- S_MWMAX_NI_GT, S_REP_NI, S_REP_ROI, and S_MWMAX_ROI_GT – combined MW output of OCGTs must be less than set MW number in Ireland and NI. This is required for replacement reserve in NI and Ireland;
- S_MWMAX_CRK_MW , and S_MWMAX_STH_MW – generation restriction in the Cork area and Southern Region; and
- other constraints that may be added from time to time.

Most respondents to the consultation supported the second option. In SEM-19-054, however, the SEM Committee decided not to implement either option but to keep Option 2 under review in light of the operation of the market arrangements, interactions with the capacity market and any future changes to the balancing market. The SEM Committee considered allowing more time before making any decision to be the most prudent approach, as this would allow for additional operational experience to be gathered, and for a better understanding of how certain changes made to the Balancing Market may impact on the area of Difference Charges.

At the time, one of the concerns in relation to the second option was that it could have an impact on the Socialisation Fund by widening the gap between Difference Charges and Difference Payments at times. Consideration was also given to the potential impact of introducing a locational element to the CRM. The concern was that, by protecting units located behind a constraint from exposure to Non-performance Difference Charges, this could create an incentive for units to be constructed at such locations.

## 2.3. Relevant Trading and Settlement Code Modifications

Since I-SEM Go-Live, the RAs are aware of a number of Trading and Settlement Code (TSC) disputes that have been raised in relation to the application of Non-performance Difference Charges during RO events. A series of related TSC modification proposals have also been raised.

In January 2021, TSC modification proposal Mod_01_21 *'Removal of difference charges where operational constraints are binding'* was raised by a market participant. The modification returned to Option 2, which had been considered in SEM-19-024. Mod_01_21 proposed removing exposure for Generators whose scheduled output cannot be increased due to any Operational Constraint that limits an increase in a unit's output. The modification aimed to achieve this by setting the Service System Flag (FSS) for a Generator Unit equal to zero for any Imbalance Pricing Period in which the Generator Unit is "*bound by the presence of an Operational Constraint relating to the provision of Replacement Reserve, or any other Operational Constraint which has a setting of 'ON' in the Imbalance Pricing System and which limits the potential output the Generator's unit*"[7]. As explained above, the System Service Flag (FSS) is currently only set to zero for units that are bound by the Replacement Reserve constraint.

Mod_01_21 was recommended for approval by the Modifications Committee but was rejected by the SEM Committee. In the Decision, the RAs acknowledged that, based on assessment of a number of RO Events to date, there would have been sufficient funding to cover the Socialisation Fund had Mod_01_21 been in place, which had been a significant concern raised by the SEM Committee in SEM-19-054. However, the RA view was that the modification was broader than necessary to address the exposure of the specific Generator Units on which the justification for the modification was based i.e. low utilisation plants entering the Balancing Market with no ex-ante position. The RAs were also of the view that if the Modification were implemented, then where a unit was constrained but that constraint did not impact on its ability to deliver its Obligated Capacity Quantity, this would remove any obligation on the unit to pay Difference Charges which could impact on incentives to deliver any of its Obligated Capacity Quantity, despite this quantity not being constrained.

Mod_02_21, '*Setting a flag for Specific Interconnector actions'*, was also raised in January 2021 as a response to perceived unfair exposure to Difference Charges, but aimed to remove Interconnector actions from pricing, rather than address the applicability of Difference Charges to generators depending on their availability. This modification was approved and was implemented in January 2022. The SEM Committee is of the view that it may be appropriate to consider refining this

[7] See Mod_01_21 Modification Proposal Form.

modification such that only certain Interconnector actions are removed from pricing, following the outcome of this current consultation on the applicability of Non-performance Difference Charges to available in-merit generators and in parallel with a re-examination of the operation of Administered Scarcity Pricing, as will be described in Section 2.4.

In August 2021, another modification proposal Mod_14_21, '*Expansion of the System Service flag to include units providing Replacement Reserve in line with the detailed design'*, was raised, which proposed to extend the System Service Flag (FSS) to cover units that are listed by the TSOs in their latest published Operational Constraints Update as a resource providing Replacement Reserve. The proposers were of the view that units were being exposed to Non-performance Difference Charges where the expectation was that they should have been flagged out as they were being held for replacement reserve. Following engagement with the RAs, an additional condition was introduced to the modification proposal that the System Service Flag (FSS) should only be applied to these units when they are available and in merit.

Mod_14_21 was approved by the Modifications Committee in December 2021 and, at the time of publication of this consultation paper, is awaiting Impact Assessment before an RA decision.

## 2.4. Discussion Paper on Scarcity Pricing and Demand Response

The link between scarcity and pricing was examined in SEM-21-042, which sought to identify measures that could be implemented in time for Winter 2021/22 to encourage the formation of appropriate price signals during times of scarcity, as well as demand side response to those signals.

That paper noted that Administered Scarcity Pricing was implemented in the Balancing Market in order to:

1. Remove the need for additional performance incentives to be introduced within the CRM by giving a strong incentive to capacity providers to be available at times of system stress.

2. Provide Suppliers with a strong incentive to provide demand side response and reduce consumption at times of system stress.
3. Reflect experience in other markets where scarcity has not delivered appropriate price signals.

Although no changes were made at that time given, in particular, the practical difficulty of implementing any such changes in time to be effective for Winter 2021/22, the SEM Committee was of the view that the interaction between Administered Scarcity Pricing, the RO Strike Price and prices in the ex-ante and balancing markets during periods of tight generation capacity margins was an area which merited further consideration in the future.

Following the outcome of this current consultation on the applicability of Non-performance Difference Charges to available in-merit generators, it is the SEM Committee's intention to re-examine the related area of operation of the Administered Scarcity Pricing mechanism.

## 3. Consultation

Following on from SEM-19-054, and taking into consideration the various TSC modifications proposed since that decision paper was published, the SEM Committee is of the view that the question of the applicability of Non-performance Difference Charges to generators that are available and in-merit, but not dispatched, warrants full consultation with industry. As stated above, the SEM Committee's intention is to subsequently re-examine the related area of the operation of Administered Scarcity Pricing.

The SEM Committee now invites feedback from interested stakeholders on the questions contained in the sections below.

## 3.1. Circumstances in which Available In-Merit Units are not Dispatched

The SEM Committee is aware that there may be different reasons why an available and in-merit unit is not dispatched by the TSO, including where the unit is located behind a constraint on the transmission system or where the unit is at a technical limit for example. The SEM Committee also acknowledges that grid development has the potential to address this issue insofar as it relates to transmission constraints.

The Grid Code provides a list of factors (see Appendix 1) that the TSO is required to take into account in their scheduling processes, which "*…will mean that, in general, strict adherence to Merit Order may not necessarily be feasible*." The latest Independent Assurance Report on the Scheduling and Dispatch process[8] refers to these factors and the need to log the reasons for deviating from the Merit Order in real time.

1. The SEM Committee requests that the TSOs provide further information regarding all of the possible reasons why, in practice, units may not be dispatched when available and in-merit. This information is required as different scenarios may need to be considered differently in the context of the applicability of Non-performance Difference Charges.
2. Feedback is requested from market participants, with supporting data where possible, as to circumstances in which units have been available and in-merit but not dispatched. While the SEM Committee's particular interest relates to circumstances that occur during an RO event, any other occurrences are of interest also, as it may be possible that the same circumstances could occur during an RO event.

## 3.2. Possible Approaches to Application of Non-performance Difference Charges

As set out in Section 2, there have been several distinct approaches implemented or proposed in relation to applying Non-performance Difference Charges to available and in-merit units that are not dispatched. The SEM Committee is aware that, where

[8] Independent-Assurance-Report-on-compliance-with-specified-elements-of-the-Scheduling-and-Dispatch-process-for-the-period-ended-31-December-2020.pdf (eirgridgroup.com)

a unit has obtained a position in the ex-ante markets and is subsequently constrained down from this position by the TSO, it will not be exposed to Non-performance Difference Charges. Given this, the SEM Committee understands that the specific units that are impacted by this issue are those that do not obtain an ex-ante position, and that are then available and in-merit in the Balancing Market, but not dispatched.

The approach to applying Non-performance Difference Charges that is effective in the Trading and Settlement Code at present, means that units are exempt from exposure to Non-performance Difference Charges that would otherwise apply, only if they are bound by the Replacement Reserve Operational Constraint. A second, slightly broader, approach is contained in Modification Proposal Mod_14_21, for which an impact assessment is currently awaited. The effect of Mod_14_21 would be to exempt units from exposure to Non-performance Difference Charges that would otherwise apply, if those units are listed by the TSOs in their latest published Operational Constraints Update as resources providing Replacement Reserve.

A third approach is that first proposed in SEM-19-024, and revisited via the modification proposal Mod_01_21, whereby units are not exposed to Non-performance Difference Charges if they are bound by any of a set of constraints that limit the potential output of a unit, and not just the Replacement Reserve constraint.

The broadest approach would be for all units which are available and in-merit to be exempt from Non-performance Difference Charges to the extent that their available capacity meets their Capacity Obligated Quantity, which may capture circumstances that would not be covered by the third approach above.

If the exemption from Non-performance Difference Charges based on availability were to be extended to a wider set of circumstances than where the Replacement Reserve constraint is binding, then the robustness of assessing availability may need to be considered. The timeframe for implementation for each of these options is also a relevant consideration.

Finally, the SEM Committee is aware that linking the RO obligation more closely to availability could interact with incentives for certain units to obtain an ex-ante position and requests respondents’ feedback in relation to this point also.

3. Under what circumstances, if any, beyond being flagged for providing Replacement Reserve, should units be exempt from Non-performance Difference Charges that would otherwise apply? Please provide supporting rationale for your response.
4. Is there any interaction with the incentives for units to trade in the ex-ante markets as a consequence of your preferred approach, or any of the approaches proposed?
5. Could these approaches introduce a detrimental locational signal into the Capacity Market (e.g. by exempting units bound by a Locational Constraint from Non-performance Difference Charges, could this send a signal to Capacity Market Units to locate behind a constraint)?

## Next Steps

The consultation will be open for a period of eight weeks, closing on 31 August 2022.

Responses to the consultation paper should be sent to Grainne Black (tsc@cru.ie) and Paul Bell (paul.bell@uregni.gov.uk) by no later than COB on 31 August 2022. All non-confidential responses will be published alongside the SEM Committee's Decision in this area. If you want your response to be treated as confidential, please tell us in your response, and explain why. Please also clearly mark the parts of your response that you consider to be confidential, and if possible, put the confidential material in separate appendices to your response.

## Appendix 1: Grid Code Section SDC1.4.7.3

In compiling the Indicative Operations Schedules in conjunction with the Other TSO, the TSO will take account of the following factors (and the equivalent factors on the Other Transmission System will be so treated separately by the Other TSO):

(i) Physical Notifications, Final Physical Notifications or Interconnector Schedule Quantities (as the case may be) submitted in accordance with SDC1.4.4.6;

(ii) Transmission System constraints from time to time, as determined by the TSO;

(iii) Reserve constraints from time to time, as determined by the TSO;

(iv) the need to provide an Operating Margin (by using the various categories of reserve as specified in OC.4.6 and CC.7.3.1.1 (as the case may be), as determined by the TSO acting in conjunction with the Other TSO;

(v) Transmission System stability considerations;

(vi) the level of MW Output and availability covered by Non Centrally Dispatched Generating Units, by Plant subject to Priority Dispatch and by Controllable PPM;

(vii) the Energy Limits for Hydro Units;

(viii) in respect of all Plant, the values of their Technical Parameters registered under this SDC1 and other information submitted under SDC1.4.4.4;

(ix) Commercial Offer Data for each CDGU and/or Controllable PPM and Demand Side Unit and equivalent commercial data provided by an External System Operator in respect of Interconnectors;

(x) the requirements, as determined by the TSO, for Voltage Control and Mvar reserves;

(xi) CDGU and/or Controllable PPM stability, as determined by the TSO;

(xii) other matters to enable the TSO to meet its Licence Standards and the Other TSO to meet its equivalent;

(xiii) the requirements as determined by the TSO, for maintaining Frequency Control;

(xiv) Monitoring and/or Testing and/or Investigations to be carried out, or being carried out, under OC.10 (as the case may be), Testing to be carried out, or being carried out, at the request of a User under OC.8 and/or Commissioning Testing under the CC;

(xv) System Tests, Operational Tests and Commissioning Tests;

(xvi) the inability of any CDGU and/or Controllable PPM to meet its full reserve capability;

(xvii) Inter-jurisdictional Tie Line limits;

(xviii) other facts as may be reasonably considered by the TSO to be relevant to the Indicative Operations Schedule;

(xix) the inflexible characteristics as declared by the Generator and abnormal risks;

(xx) losses on the Transmission System and on the Other Transmission System;

(xxi) requirements within any Constrained Group;

(xxii) factors used by the TSO (and the Other TSO) in order to comply with Statutory Instruments, Statutory Regulations and/or the Licence which may impact scheduling and Dispatch; 285

(xxiii) factors used by the TSO (and the Other TSO) to comply with the objectives in SDC1.2(g);