Decision paper

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

SEM-23-029

29 March 2023

EXECUTIVE SUMMARY

The SEM Committee published a consultation paper (SEM-22-030[1]) in July 2022, regarding the applicability of Reliability Option Non-Performance Difference Charges (NPDCs) to available in-merit units. Feedback was requested from the TSOs and from market participants as to the circumstances in which Capacity Market Units can be available and in-merit, but not dispatched. The paper also set out several possible approaches to applying NPDCs to available in-merit units and requested stakeholders' views on these approaches, or others that they might identify. The RAs then held a series of bilateral meetings with respondents in October 2022. This Decision paper summarises the feedback received from industry through the written responses and the bilateral meetings. It sets out the SEM Committee's views in response and the SEM Committee's decisions, having taken on board all feedback received.

The responses received to the consultation indicated a broad range of scenarios in which units may not be dispatched and hence subject to Non-Performance Difference Charges, despite being available and in-merit. In particular, the TSOs provided a detailed list of the scenarios that they have identified. This list is contained in Appendix 1 to this paper. The scenarios include those in which units are not dispatched due to constraints of different kinds, but also due to decisions taken by the TSOs during the Scheduling and Dispatch process.

The Consultation paper set out 4 options for the circumstances in which units should be exempt from NPDCs. The majority of respondents supported Option 4, which would remove exposure to NPDCs for "*units that are available and in-merit to the extent that their available capacity meets their Capacity Obligated Quantity",* with some supporting Option 3, which would remove exposure for *"units that are bound by any constraints that limit the potential output of a unit, and not just the Replacement Reserve constraint".*

Given that the approach of extending the exemption from exposure to NPDCs to "*units that are bound by any constraints that limit the potential output of a unit, and not just*

[1] https://www.semcommittee.com/publications/sem-22-030-consultation-applicability-reliability-option-non-performance-difference

the Replacement Reserve constraint" would still result in the exposure of units which are available and in-merit due to circumstances beyond their control, the SEM Committee has decided to extend the exemption from exposure to NPDCs to "*units that are available and in-merit to the extent that their available capacity meets their Capacity Obligated Quantity"* (Option 4 presented in the consultation paper).

The implementation of this solution requires clear definitions for how units should be considered "in-merit", and for the determination of availability. The SEM Committee has decided that "in-merit" should be defined based on a comparison of the Obligated Capacity Quantity Complex Price[2] and the Imbalance Settlement Price. Availability is defined in line with the existing definitions in the EirGrid and SONI Grid Codes, and with "Actual Availability Quantity" in the Trading and Settlement Code (TSC).

The TSOs are requested to implement the changes set out in this Decision, and to monitor the impact on the Socialisation Fund going forward.

[2] This is currently the Capacity Obligated Quantity Complex Price but is to be renamed the "Obligated Capacity Quantity Complex Price" as the defined term in the TSC for the quantity itself is the "Obligated Capacity Quantity" and not the "Capacity Obligated Quantity".

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Glossary of Terms and Abbreviations

Abbreviation or Term	Definition or Meaning
BESS	Battery Energy Storage System
BM	Balancing Market
CHP	Combined Heat and Power
CMU	Capacity Market Unit
CRM	Capacity Remuneration Mechanism
DAM	Day Ahead Market
DSU	Demand Side Unit
FPN	Final Physical Notification
INC	Incremental Price Quantity Pair
I-SEM	Integrated Single Electricity Market
NPDCs	Non-Performance Difference Charges
RAs	Regulatory Authorities
RO	Reliability Option
SEMC	Single Electricity Market Committee
SEMO	Single Electricity Market Operator
TSC	Trading and Settlement Code
TSO	Transmission System Operator

1. Introduction

This Decision paper follows the publication of Consultation paper SEM-22-030[1] in July 2022, and the series of bilateral meetings held with respondents in October 2022. 15 responses were received to the Consultation, of which 4 were marked wholly or in part confidential. All non-confidential responses are published alongside this paper.

1.1 Background

Participants that are successful in a Capacity Auction take on a "Reliability Option" (RO). The RO creates an incentive to deliver energy at times of scarcity 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, there have been Capacity Market Units that have declared available, and been in-merit, but have not been dispatched. These units have been exposed to Non-Performance Difference Charges and in some instances, have raised disputes 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[3]. It was decided in SEM-19-054[4] 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. Given the additional operational experience in the market since the matter was first consulted on, the SEM Committee decided to re-examine the issue in SEM-22-030.

[3] https://www.semcommittee.com/publications/sem-19-024-balancing-market-and-capacity-market-options-consultation-paper
[4] https://www.semcommittee.com/publications/sem-19-054-balancing-market-and-capacity-market-options-decision-paper

1.2 Information sought in the Consultation paper

SEM-22-030 requested 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 sought views on several possible approaches to applying NPDCs to available in-merit units and requested stakeholders' views on these approaches, or others that they might identify. The approaches outlined were as follows:

1. 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 (this was the status quo at the time the Consultation paper was published, but has now been superseded by Option 2).
2. Units are exempt from exposure to Non-Performance Difference Charges that would otherwise apply if they are listed by the TSOs in their latest published Operational Constraints Update as resources providing Replacement Reserve (this approach is now the status quo, having been implemented through Mod_12_22[5], which was previously Mod_14_21).
3. Units are exempt from exposure to Non-Performance Difference Charges that would otherwise apply if they are bound by any constraints that limit the potential output of a unit, and not just the Replacement Reserve constraint.
4. Units are exempt from exposure to Non-Performance Difference Charges if they are available and in-merit to the extent that their available capacity meets their Capacity Obligated Quantity (the broadest approach).

1.3 Consultation process

The consultation was published on 6 July 2022 and ran for 8 weeks, closing on 31 August 2022. 15 responses were received, of which 4 were marked wholly or in part confidential. The 12 non-confidential responses (or non-confidential portions of responses) summarised here include:

- Bord Na Mona
- Bord Gáis Energy
- Demand Response Association Ireland (DRAI)

[5] https://www.sem-o.com/documents/market-modifications/Mod_12_22/Mod_12_22DecisionLetter.pdf

- Electricity Association of Ireland (EAI)
- EirGrid and SONI (TSOs)
- ENEL-X
- Energia
- Energy Storage Ireland (ESI)
- ESB GT
- Federation of Energy Response Aggregators (FERA)
- GridBeyond
- SSE

The RAs subsequently held a series of bilateral meetings with respondents, which took place in October 2022. The summary of responses in the following section draws from both the written submissions and follow-up bilateral meetings.

2. Summary of responses

2.1 Circumstances in which Available In-merit Units are not dispatched

Question 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.

The TSOs provided what they described as a “relatively exhaustive” list of 21 different circumstances, under which units may not be dispatched when available and in-merit. This list is contained in Appendix 1 to this paper. These circumstances are varied, and arise for reasons including network, operations or unit constraints, reserve, or TSOs decision-making. Some can be grouped under the heading of “operational constraints” and some under the heading of “scheduling and dispatch decisions”. Further engagement with the TSOs showed that while some of the operational constraints scenarios could be flaggable and hence the removal of NPDCs could potentially be automated for those particular circumstances, the majority of scenarios (involving both the categories of “operational constraints”, and “scheduling and dispatch decisions”) would require manual removal of NPDCs, subject to the availability of supporting evidence or data, which may not be conclusive.

Although this question was primarily directed at the TSOs, some market participants also made relevant comments in response.

FERA made the point that "*TSO actions must be justifiable and logged*", suggesting that "*the Merit Stack should be published for times of Scarcity, and the difference between a TSO merit stack and a SEMO merit stack should be highlighted and explained*". GridBeyond stated that "*there are numerous instances where DSUs have been available but not dispatched during RO events and other times of system stress*", adding "*we do not believe there is a realistic means of avoiding these situations without overly constraining the TSOs' actions. Our preference is for a solution which extends protection to those units impacted by TSO decisions, where they have no ability to avoid the resultant penalties through their own actions*."

SSE "*encourage the TSO to provide the necessary data as requested in Q1*" and "*strongly support the position of the EAI that this list of scenarios should be shared*". ESB GT acknowledged *"the significant work that the TSO contribute to the Market Operator User Groups and the detailed information on the operation of the system provided through these groups*".

<u>SEM Committee response</u>

The SEM Committee welcomes the detailed information provided by the TSOs in response to this question, which has been critical in informing the decisions set out in this paper. The contributions of market participants in this respect are also welcomed. The SEM Committee acknowledges the complexity of the circumstances under which the TSOs operate and recognises the need for Scheduling and Dispatch decisions to be taken during times of system stress.

The SEM Committee also recognises the benefit of increasing transparency around the scheduling and dispatch decision making process, as it was apparent from market participants' responses to Question 2 (as summarised below) that participants have little visibility in some cases of the reasoning behind individual dispatch decisions taken by the TSOs. In this context, the full list of circumstances provided by the TSOs is included in Appendix 1 to this paper.

Question 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.

Bord na Mona referenced being "*directly financially penalised when a peaker was in-merit and available in the past*", although they note that "*a number of modifications, including Mod 09-19 'Removal of Locational Constraints from Imbalance Pricing Calculation' have addressed this constraint in the Imbalance pricing process, which today would avoid this unfair penalty.*" Bord Gáis Energy described circumstances, which they say "*show that even large CCGTs are exposed to potential RO Difference Charges if a strike event were to occur even if the unit is in merit and economically reliable for dispatch but not run due to system constraints and/or TSO dispatching decisions*."

The circumstances that ESB GT note in which available in-merit units are not dispatched are those that have been highlighted through the related modifications raised to the TSC, including N-S tieline overflagging and transmission constraints. They state that it should be recognised that most of these issues have been addressed by the targeted modifications already raised, and that changes in this area should similarly be targeted and address a specific issue.

DRAI referenced *"numerous instances where DSUs have been available but not dispatched during RO events and other times of system stress",* while FERA provided examples from members "*of times when they believe their bidding strategies would have resulted in dispatch, but the TSO did not dispatch. This included times when the BM price was above the bids (Complex and/or Simple)* [and] *during times of extreme high prices".* ENEL-X made the point that "*Long-run CHP DSUs participate in the Capacity Market by increasing demand at times of high generation in response to dispatch instruction from SO. This type of unit will not be dispatched at times of tight capacity."*

ESI reference "*current interim TSO policy* [which] *is that BESS will not be dispatched or scheduled (except in limited circumstances at the discretion of the TSOs) and will instead primarily be held for reserve."* They state that this prevents BESS market participants from managing RO risk and emphasise that units should not be penalised due to a TSO system limitation.

SEM Committee response

The SEM Committee welcomes the insight provided by participants in response to this question. From the feedback received, it was apparent that it was not always clear to participants why the units concerned had not been dispatched. The TSOs' list of circumstances, contained in Appendix 1 to this document, should help to provide transparency as to the reasons behind dispatch decisions that result in available in-merit units not being run.

In the case of BESS, the position is somewhat different in that it is a known limitation in the Scheduling and Dispatch process that leads to such units not being dispatched as standard (which also means in effect that the reason for non-dispatch is clearer and known in advance). In this context, the SEM Committee welcomes the inclusion of the "Integration of Energy Storage Power Stations" workstream within the TSOs' recently launched Scheduling and Dispatch project.

In regards to long-run CHP DSUs, the SEM Committee understands that from a Capacity Market point of view, such units are essentially providing demand response (reduction) at all times, other than when they increase demand at times of high renewable penetration and low demand. As such, the SEM Committee understands that these units are providing demand response during times of tight capacity margins, and thereby meeting their obligations under the RO.

2.2 Possible Approaches to Application of Non-Performance Difference Charges

Question 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?

Many respondents were in support of the broadest approach (Option 4) described in the Consultation paper, whereby all units which are available and in-merit would be exempt from NPDCs to the extent that their available capacity meets their Capacity

Obligated Quantity. A number of respondents called for further industry engagement, to be informed by the response provided by the TSOs to Question 1 above, regarding the circumstances in which available in-merit units are not dispatched.

Bord na Mona supported Option 4, stating that NPDCs "*should be targeted to those circumstances where units can have direct control in influencing their delivery*", a view shared by EAI. DRAI urged the protection of units providing a broader range of DS3 services, stating that "*units who are acting under TSO instruction (not to be dispatched despite being in-merit and available to meet capacity market obligations) should not be exposed to NPDC*." They made the additional point that "*it is better to extend protection to units impacted by TSO decisions than to constrain the actions open to the TSO in operating the power system*". GridBeyond stressed that "*units that are ready and available, should not be exposed to difference charges as a results of TSO actions beyond their control*". Energia stated that they "*see a need for an overarching solution where a generator could have met its obligations but through no fault of its own for any reason (be that system or TSO action/inaction) it was not dispatched to deliver the capacity*."

Bord Gáis Energy proposed the concept of being "*economically reliable for dispatch*", by which they mean that "*the unit has bid into the Day Ahead Market, the unit has submitted a Final Physical Notification to the System Operators, has provided Bid/Offer prices to the SOs; and has declared the unit as available for dispatch to the SOs*." Where a unit has fulfilled these criteria, then NPDCs should only apply where "*non-performance is evidenced*". On the contrary, "*where no sync instruction is given to an offline unit that has made itself economically reliable for dispatch, then there is no question of non-performance by the unit and so no non-performance charges will apply*."

The concept of being "*economically reliable for dispatch*" was discussed during the bilateral meetings held with respondents, during which a number of issues were raised in relation to the proposed requirement to have bid into the Day Ahead Market (DAM). For smaller units, and DSUs in particular, who do not necessarily participate in the ex-ante markets, it was considered that the costs of ex-ante trading are prohibitive. In addition, a number of parties made the point that scarcity events are not usually seen in the ex-ante markets, and that RO events are not predictable, with no notice given to prompt ex-ante trading.

ENEL-X reiterated that "*as the purpose of [a long-run CHP] DSU is to run at times of high generation, this type of DSU will not be dispatched at times of tight capacity".* Therefore, this type of unit should be exempt from NPDC. ESI stated that units should be exempt when they are held back for system services and at times when system imbalance price triggers RO event.

ESB GT referenced TSC Mod_01_21, stating that it was unclear why this modification proposal had been rejected by the RAs, and seeking clarification regarding the interaction between this modification proposal and the Difference Charge calculation in the TSC. They also questioned the implications in regard to the CRM State Aid decision of a potential change in this area.

FERA considered that "*If the TSOs treat the unit as having abilities outside providing 'Replacement Reserve' and use these to impact dispatch decisions, then these should be used to flag the unit. Other groupings, such as constraints, are external matters for the TSOs and may result from overloaded wires, shortage of emergency generation, abundance of Renewable generation".*

SSE listed the following circumstances as appropriate for exemption: "*When on planned outage, under test, when a plant is under system constraint, where any portion of a unit's MEC is non-firm, when a plant is curtailed, if not in-merit and not needed by the TSO for any reason*", adding furthermore that "*units should not be exposed to risks outside their control*".

The TSOs recognised *"the financial risk market participants may be exposed to in the application of NPDC in circumstances outside of their control*" and considered that "*extending exemptions to units covered by operational constraints is appropriate*".

<u>SEM Committee response</u>

The SEM Committee notes that the majority of respondents supported the broadest approach, and many argued that it was appropriate on the basis that market participants should not be exposed to NPDCs for reasons that are outside of their own control. The SEM Committee acknowledges that, based on the list of circumstances provided by the TSOs and contained in Appendix 1, there may be many reasons why a unit is not dispatched, over which that unit has no influence. These reasons may be related to constraints or may be down to the judgement of the TSOs in dispatching the system.

In regard to the concept of being "economically reliable for dispatch" – which would mean that the unit has bid into the Day Ahead Market (DAM), submitted a Final Physical Notification (FPN) to the System Operators, provided Bid/Offer prices to the SOs and declared the unit as available for dispatch – the SEM Committee notes that it is already a requirement under the TSC (Part B D7 Physical Notification Data and Part B Appendix I Commercial Offer Data) to submit FPNs and Bid/Offer prices. It is also already an assumption for present purposes that a unit would need to declare available (as well as be in-merit) in order for NPDCs to potentially not be applied. Consequently, the additional requirement that would be imposed by the concept of "economically reliable for dispatch" is the need to have bid into the DAM.

The SEM Committee acknowledges the rationale for the approach proposed, but considers that obliging ex-ante bidding would be excessive, for smaller units in particular. The SEM Committee sees value in the idea that non-performance should be "evidenced", as referred to in the sections that follow.

As regards the interaction of a change in this area with the CRM State Aid Ruling and the point raised by some respondents that the emphasis during the high level design phase of the CRM was on delivery rather than availability, the SEM Committee notes that this is not a principle that the State Aid Ruling itself enshrines. In fact, it refers specifically to availability in the context of the Reliability Option, as in the excerpts below for example:

(57) "*By being subject to difference payments at times when prices are high, the capacity providers have a financial incentive* ***to be available*** *at times of scarcity, because the payment has to be made irrespective of whether they were selling electricity during the settlement period*." [emphasis added]

(40) "*For intermittent renewables plants, mandatory bidding does not apply, reflecting the fact that penalties for* ***non-availability*** *may outweigh the benefit of option fees for these capacities*." [emphasis added]

Regarding the decision on TSC Mod_01_21[6] and the clarification sought, the RAs would like to confirm that the decision letter should have referred to Non-Performance Difference Charges, rather than Difference Charges.

Question 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?

Limited commentary was received in response to this question. Bord Gáis Energy's view was that under their proposed approach there was "*no change to the incentive for units to trade in the ex-ante markets as the risk remains that units may be exposed to RO Non-Performance Difference Charges due to unexpected, fast evolving strike events with the inability to self-commit under the SEM*". ESI noted that storage is currently disincentivised from trading in the ex-ante markets due to the resulting Imbalance price exposure, with most units classified as non-firm.

ESB GT made the comment that "*it is not until after the pricing has been determined that generators will know if a constraint was binding on a 5 min period. Subsequently, there is no guarantee that a constraint flag will be binding at the time of the RO and thus it is not something that generators can rely on post the RO period*". FERA observed that "*for Demand Side Response, the majority of trades are in the Balancing Market. Ex-ante trades are monetary decisions rather than trying to avoid any scarcity obligations*".

SEM Committee response

The SEM Committee observe that while limited commentary was received in this area, the consistent view, where expressed, was that incentives to trade in the ex-ante markets would not be impacted.

[6] https://www.sem-o.com/documents/market-modifications/Mod_01_21/DecisionLetteronMod_01_21.pdf

Question 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)?

Many respondents shared the view that any locational incentive created by exposure to Non-Performance Difference Charges would be minimal in comparison to other factors that influence where a unit will be located. There was also a common view that locational signals are already embedded within the CRM design.

Bord na Mona stated that "*locational signals are already clearly articulated in the market via CRM auction parameters, constraints and curtailment faced in certain constrained regions, and firm access limitations related to delayed network development in a particular region".* They shared the EAI view that "*exposure to RO difference charges should not be used as a locational signal*".

During the bilateral discussion with the TSOs, they clarified that they considered the risk of such locational signals to be non-material. ESI were of the view that the approaches put forward *"would not introduce a detrimental locational signal as a natural incentive would remain*." ESB GT considered that any potential locational signals would have "*smaller impacts than other factors*". FERA observed that "*Locational Constraints should work in tandem with firm access, otherwise dispatch of all available capacity may overload the distribution/transmission system.*" SSE stated that "*There are sufficient constraint signals in the CRM at present. The CRM should not be continuously used to address constraints*."

SEM Committee response

The SEM Committee wishes to clarify that the question was not seeking to frame Non-performance Difference Charges as a potential locational signal but to understand inadvertent impacts of the approaches being explored. The SEM Committee considers that the inadvertent locational signals potentially resulting from the approaches proposed in the Consultation paper, do not represent a significant concern in this instance.

2.3 Other areas raised by respondents

2.3.1 Interaction with ASP

Concern was raised by several market participants in their submissions at the apparent conflation of the issues of applicability of Non-performance Difference Charges and Administered Scarcity Pricing. The RAs clarified during the course of the bilateral meetings that the intention was not to conflate these two issues, but simply to flag that the related question of sharpening the scarcity signal would be dealt with separately and subsequently to this Consultation and Decision, once the question of applicability of Non-performance Difference Charges has been resolved satisfactorily.

2.3.2 Definition of "in-merit"

Several market participants highlighted the importance of a clear and common understanding of how "*in-merit*" should be defined.

EAI commented that "*In-merit is a term which can be defined either as: 1) Units that are less than the highest INC* [incremental price quantity pair] *or 2) Units that are less than the Imbalance Price (and therefore should be called before the event).",* adding moreover that *"members would welcome clarity on the working definition being used before these proposals can be fully understood*."

The TSOs observed that "*Any "in-merit" test for exempting an available unit that is not dispatched is problematic to implement in real time and pricing timeframes, i.e. through a flagging methodology. Achieving this approach may be effectively implementable in Settlement timeframes through manual rework - subject to the availability of a clear set of criteria governing the "in-merit" test*."

FERA noted that "*The consultation by the SEMC has identified that there are times when units have been "in-merit" but have not been dispatched. The understanding of that statement is that the unit has a bid (Complex or Simple) that is lower than the Balancing Market price."*

Bord na Mona "*underline the need for absolute common understanding of what is meant by "availability*" *and "in merit"*". Energia pointed out that when this issue was investigated in SEM-19-024 and Mod_01_21, the concept of units needing to be "*in-merit*" was not included. They also highlight that the approach proposed in the Consultation paper of defining "*in-merit*" relative to the price in the Balancing Market is not consistent with the approach taken in Mod_12_22 (previously Mod_14_21) where "*in-merit*" is defined relative to the RO Strike Price. They argue that the appropriate definition of “in-merit” should be “*units that bid less than the highest accepted INC*”.

SEM Committee response

The SEM Committee agree with respondents that a clear definition of “in-merit” is required in this context. The SEM Committee notes that the definition stated in the Consultation paper was “*relative to the price in the Balancing Market*”. However, there is also a need to specify what commercial data would be used to compare to the Balancing Market price. The decisions that have been reached in this regard are set out in Section 3 of this paper, along with the definition of “*available*”, for which a similar need for clarity would apply.

In regard to the consistency of approach with Mod_12_22, which defined “in-merit” in terms of a comparison between the Obligated Capacity Quantity Complex price and the RO Strike Price, the RAs noted in the decision letter on this modification that they may “*seek in the future to align the operation of this modification, as appropriate, with any changes that result from the decision on SEM-22-030*”.

The concept of a unit being “in-merit” had not been included in SEM-19-024 (nor Mod_01_21, which replicated the proposal contained in SEM-19-024), in part because the proposal was not progressed to implementation at that time. However, the SEM Committee considers it important to include the “in-merit” requirement, as a unit can only have a reasonable expectation of being dispatched if it is “in-merit”. This is not the case if the unit is out of merit, even if it is available during an RO event.

2.3.3 Availability declarations

Discussions with market participants on the definition of availability, as well as the issue of assessing and ensuring availability, pointed to existing rules within the Grid Codes. Availability is defined within the EirGrid Grid Code[7] as:

“At any given time the measure of Active Power a Generation Unit(s) is capable of delivering to the Connection Point... In terms of a Demand Side Unit, the Demand Side

[7] https://www.eirgridgroup.com/site-files/library/EirGrid/GridCode.pdf

Unit MW Capacity as the measure at any given time of the capability of the Demand Side Unit to reduce Demand…"

And within the SONI Grid Code[8] as:

"In respect of any period…… the capability of the CDGU or Controllable PPM to generate electricity during that period….. for Demand Side Units….the capability of the Demand Side Unit to reduce Demand during that period;…… for Aggregated Generating Units…..the capability of the Aggregated Generating Units as a whole to generate electricity during that period;"

The Grid Codes (SDC1) require that each User shall, by not later than Gate Closure 1 each day, notify the TSO (of their availability) by means of an Availability Notice[9]. Units are then listed as available on the TSOs' Electronic Dispatch Instruction Logger (EDIL).

The TSOs noted however that "*availability is not physical (it amounts to a signal or declaration) and therefore not confirmed or measured until dispatched. With an availability approach, participants could be incentivised to be available only to their obligated capacity quantity level, as this would ensure they are covered, and not available to higher levels they could operate at (although this is technically mandated in the Grid Codes).*" They also stated that "*if an availability-based approach is implemented it should be considered whether incentives to deliver when dispatched are adequate. Availability can change after dispatch – meaning a unit can appear available and "in-merit" but after it is dispatched it declares down and is desynced*."

In regard to the reliability of availability declarations, FERA observed that the Grid Code allows testing by the TSOs of units where availability is in doubt, while noting that testing has fallen off since the introduction of the new market arrangements and the introduction of the Reliability Option. The TSOs made the point that most units would be tested over tight periods, and that reserve units could be rotated to facilitate this. The TSOs also referenced the existence of Other System Charges (OSC) which are levied on generators that fail to provide necessary services to the system, leading

[8] https://www.soni.ltd.uk/media/documents/Feb23_SONI-Grid-Code.pdf
[9] A User may satisfy this obligation by submitting the data under the TSC, unless the TSO requires, by notice to the User, the data to be submitted to it directly under the Grid Code.

to higher Imperfections Costs. The OSC include charges for generators if their unit(s) trip, or make downward re-declarations of availability, at short notice.

<u>SEM Committee response</u>

The SEM Committee agrees that the correct definition of Availability in this context is that contained in the Grid Codes, and as declared in the declarations of availability made under the Grid Codes, with the relevant quantity in the Trading and Settlement Code (TSC) being the "Actual Availability Quantity".

With regard to the view that participants could be incentivised by a change to the application of Non-Performance Difference Charges to be available only to their obligated capacity quantity level, and not available to higher levels they could operate at, the SEM Committee notes that the exposure under the Reliability Option is only up to a unit's obligated capacity quantity as it stands. That is to say that the SEM Committee cannot see that there would be any *reduction* in the incentive to be available beyond the obligated capacity quantity as a result of a change to the application of Non-Performance Difference Charges such as that contemplated in this paper.

In regards to those circumstances where a unit has declared available, but proven unavailable upon receiving a dispatch instruction, the SEM Committee considers that the unit is clearly unavailable in that case, and there is no question that it should be exempted from Non-Performance Difference Charges. Its non-performance has been "evidenced".

Regarding the reliability of availability declarations, in addition to the incentive created by Other System Charges, the SEM Committee notes the following obligations under the Grid Codes:

"*SDC1.4.3.2* ***Each Generator****, and where relevant each Generator Aggregator,* ***shall****, subject to the exceptions in 0 and SDC1.4.3.3A,* ***use reasonable endeavours to ensure that it does not at any time declare*** *in the case of its CDGU, Controllable PPM, or Aggregated Generating Unit,* ***the Availability*** *or Technical Parameters* ***at levels*** *or values* ***different from those that the*** *CDGU, Controllable PPM, and/or an Aggregated Generating* ***Unit could achieve at the relevant time****. The TSO can reject* *declarations to the extent that they do not meet these requirements*." [emphasis added]

"*SDC1.4.3.4* ***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*." [emphasis added]

Notwithstanding this, the SEM Committee is of the view that it would be appropriate for the TSOs to consider whether additional testing would be warranted by a change to the application of Non-Performance Difference Charges.

3. SEM Committee decisions

3.1 Scenarios to exempt

Of the approaches presented in the consultation paper, Option 1 whereby "*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*" has since been superseded by Option 2 as a result of the approval of Mod_12_22 "Extension of System Service Flag to cover Replacement Reserve Resources"[5]. Option 2 was that "*units are exempt from exposure to Non-performance Difference Charges that would otherwise apply if they are listed by the TSOs in their latest published Operational Constraints Update as resources providing Replacement Reserve*". This option now represents the status quo, having been effective in the Trading and Settlement Code since November 2022.

The RAs requested additional information from the TSOs to supplement the appendix provided in their submission, to understand how many of the circumstances under which available in-merit units may not be dispatched would be captured by Option 3, extending the exemption from exposure to Non-performance Difference Charges to "*units that are bound by any constraints that limit the potential output of a unit, and not just the Replacement Reserve constraint*". This additional information is also shown in Appendix 1, with circumstances captured by Option 3 in green. It emerged that only 8 of the 21 circumstances listed fall under the heading of “Operational Constraints”, while the remaining 13 can be grouped under the informal heading of “TSO Scheduling and Dispatch decisions”. Available in-merit units falling into the latter category and not dispatched as a result would still be exposed to Non-Performance Difference Charges. This would include for example, the circumstances described in item 17 in Appendix 1, where “a *generator which is less reliable in successfully synchronising or which may take a number of attempts to reach stability may be started before a unit which has performed more reliably*”, and where the “more reliable” generator could be exposed to Non-Performance Difference Charges as a result.

If Option 3 were implemented, there could still be many circumstances therefore in which available in-merit units are not dispatched during an RO event due to circumstances beyond their control. As a result, **the SEM Committee has decided to extend the exemption from exposure to Non-Performance Difference Charges to “*units that are available and in-merit to the extent that their available capacity meets their Obligated Capacity Quantity*”** (Option 4 presented in the consultation paper). In effect, this will mean that non-performance must be evidenced. For the avoidance of doubt, where a unit has declared available, but then failed to meet a dispatch instruction, this is a clear case of non-performance. While it is the Obligated Capacity Quantity that is relevant to the calculation of Non-Performance Difference Charges, the SEM Committee notes that this is separate to the obligation contained in the Capacity Market Code (I.1.2.1(b)) for participants to “*dedicate and use reasonable endeavours to make available the Awarded Capacity*” [emphasis added].

The SEM Committee also notes the greater practicality of implementation of Option 4, compared to an approach that attempts to carve out specific circumstances.

3.2 Definition of “in-merit”

The definition of “in-merit” in Mod_12_22 was that a unit shall be considered in-merit where its Obligated Capacity Quantity Complex Price is less than or equal to the Strike Price, where the Obligated Capacity Quantity Complex Price is the price associated with the Price Quantity pair corresponding to the Obligated Capacity Quantity, submitted in the Generator’s Complex Bid Offer Data. However, the SEM Committee noted the potential interaction between that modification and SEM-22-030 and stated in its decision letter that they may seek in the future to align the operation of this modification, as appropriate, with any changes that result from the decision on SEM-22-030 (i.e., this paper).

A number of variations on the definition of “in-merit” used in Mod_12_22 have been considered by the RAs. In addition to the feedback discussed in Section 2.3.2, considerations in this regard have included whether to use Complex or Simple Offer data, how to account for start-up and no-load costs, as well as whether the Strike Price, the Imbalance Price or the highest accepted INC would be appropriate.

Given that the Complex Offer data is regulated, the SEM Committee has decided to continue to use this in the definition of “in-merit”, which is consistent with the approach implemented through Mod_12_22. The final selection of the ‘Obligated Capacity Quantity Complex price’ in Mod_12_22 as implemented over the original drafting of the Mod in which the Minimum Complex Price was envisaged as the price for comparison was due to the fact that, in principle, it would be possible for a very small proportion of a unit’s capacity to be offered in at a price that was less than or equal to the Strike Price, with the remaining, and large, portion of the unit’s Capacity Obligated Quantity being offered in at a price above the Strike Price.

In relation to start-up and no-load costs, it is challenging to account for these, as it would require an estimation of a hypothetical duration of dispatch for a unit that has not actually been dispatched. Given this, the SEM Committee has decided to continue to use the ‘Obligated Capacity Quantity Complex price’, which is the price associated with the Price Quantity pair corresponding to the Capacity Obligated Quantity, submitted in the Generator’s Complex Bid Offer Data.

As regards the price to compare to the ‘Obligated Capacity Quantity Complex price’ in order to determine if a unit is in-merit or not, the SEM Committee has decided that the Imbalance price is appropriate. The purpose of assessing whether a unit would have been in-merit or not, is to test whether that unit could have had a reasonable expectation of being dispatched given its position in the market. The Imbalance price is the price below which a unit could reasonably consider it should have been dispatched, when available. Using the highest accepted INC would encompass non-energy actions, which may have been taken for locational constraint reasons for example, and was discounted on this basis.

The SEM Committee has decided that the Capacity Obligated Quantity Complex Price and the Imbalance Settlement Price should be used to determine if a unit is in-merit. The SEM Committee note that the definition of in-merit in this Decision will supersede the existing definition of in-merit implemented through Mod_12_22, and moreover that this Decision will supersede Mod_12_22 in its entirety. A Modification to the TSC will be raised to implement this Decision.

3.3 Definition of availability

As set out in Section 2.3.3, the SEM Committee confirms that "availability" as referred to in this paper is in alignment with the definitions in the Grid Codes and with the Actual Availability Quantity in the TSC.

4. Other considerations

4.1 Implementation

The RAs requested additional information from the TSOs on the implementation of Option 4 as laid out in the Consultation paper. The TSOs provided a description of the implementation approach to removing exposure to Non-Performance Difference Charges for each of the circumstances listed in Appendix 1. Of the 21 circumstances listed, at least 17 of these (shown in red in Appendix 1) would require fully manual removal of Non-Performance Difference Charges, subject to the availability of supporting data, which the TSOs consider may not be conclusive. Even of the 8 operational constraints, the TSOs suggest that it may only be possible to fully automate 4 through flagging.

For Option 4, the TSOs provided the following assessment: *"Implementing an availability-based approach systematically would require significant system changes that would take a number of years to implement, and which would compete with the implementation of other significant priorities. Therefore, if clear, objective criteria could be derived and applied in settling the application of Non-Performance Difference Charges it may be preferable in the shorter term. Ex-post analysis and settlement/resettlement for infrequent events would likely be easier compared to the constraints approach as long as the criteria was unambiguous and the necessary data available."*

The RAs will raise a Modification to give effect to this Decision, and the SEM Committee requests that SEMO put in place the necessary processes to implement it in the near term. This decision sets out clear criteria under which Non-Performance Difference Charges should not be applied.

4.2 Socialisation Fund

The SEM Committee is conscious that the balance between Difference Charges and Difference Payments will be impacted by this change in approach to the application of Non-Performance Difference Charges as it will mean that in some circumstances some units that would currently pay Non-Performance Difference Charges will no longer do so. The SEM Committee notes that the balance in the Socialisation Fund currently is relatively high, and that the difference payment socialisation charge (socialisation fund tariff) has been set to zero for this year[10]. However, the SEM Committee also considers that it would be appropriate to monitor the impact of this decision on the Socialisation Fund going forward and potentially consider further adjustments and clarifications if necessary.

5. Next steps

The RAs will raise a Modification to give effect to this Decision and the SEM Committee requests that SEMO monitor the impact on the Socialisation Fund going forward.

[10] https://www.semcommittee.com/news-centre/i-sem-parameters-decision-202223-tariff-year

Appendix 1

The TSO provided an appendix containing the initial columns as part of their written submission to the consultation, and the last two columns during the course of bilateral engagement with the RAs.

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.			Type of scenario. Circumstances captured by Option 3 *"Units … bound by any constraints that limit the potential output of a unit…"* are shown in green.	Implementation for removing exposure to Non-performance Difference Charges. Circumstances which would require manual removal of NPDC are shown in red.
1.	Primary Operating Reserve Requirements	Primary Operating Reserve (POR) is maintained in line with minimum requirements: 75% of Largest Single Infeed on an all-island basis subject to a minimum of 150 MW in Ireland and 50 MW in Northern Ireland. POR is typically provided by numerous online units. The POR provision of these units varies with their MW availability / output and would be zero at their maximum availability.	Operational Constraint	Manual removal of non-performance difference charges would be required subject to the availability of the relevant RTD SO flag. SO flag may be available however the flag would be produced by RTD scheduler which is not fully reflected in actual dispatch.

2.	Replacement Reserve Requirements	Replacement Reserve is the active power reserves available to restore or support the required level of exhausted Frequency Restoration Reserves (Tertiary Operating Reserves) after a frequency event in order to be prepared for additional system imbalances, including generation reserves. Replacement Reserve provision may include online and offline available in-merit units.	Operational Constraint	Currently implemented through a System Service flag produced by the RTD scheduler which is not fully reflected in actual dispatch. System Operators determine and may change TCG cohort or remove TCG.
3.	Optimising Operating Reserve with the Largest Single Infeed	The All-Island requirement for Operating Reserve (Primary, Secondary, and Tertiary) ranges from 75% to 100% of the Largest Single Infeed. Reducing the Largest Single Infeed reduces the reserve requirement and associated cost.	Scheduling and Dispatch Decision	Manual removal of non-performance difference charges would be required subject to the availability of supporting evidence/data which may not be available/conclusive.
4.	Transmission (Network) Constraints	A unit may be dispatched below its availability due to its direct contribution to risks associated with thermal constraints on the transmission network - either during intact networks conditions or as a result of a transmission contingency or outage (including transmission outages which prevent export entirely).	Scheduling and Dispatch Decision	Manual removal of non-performance difference charges would be required subject to the availability of supporting evidence/data which may not be available/conclusive.
5.	Operational Constraints	A unit which is expensive with reference to the merit order may be started for non-energy reasons to satisfy Transmission Constraint Groups (TCG) e.g. voltage support, dynamic stability. While operating at minimum stable generation, a non-marginal flag would bind. Subsequent incremental (energy) actions would remove this non-marginal flag and could feed through to set the imbalance price while units with lower incremental prices are not used due to their start up costs.	Operational Constraint	Manual removal of non-performance difference charges would be required subject to the availability of supporting evidence/data which may not be available/conclusive. Review and complex analysis of events likely required. System Operators determine and may change TCG cohort or remove TCG.
6.	Voltage Support Capability	A generator unit may offer an increased level of voltage support (+/- MVAr) at a MW output level below full availability.	Scheduling and Dispatch Decision	Manual removal of non-performance difference charges would be required subject to the availability of supporting evidence/data which may not be available/conclusive.
7.	Tie Line / Inter-Area Limitations	There is limited transmission capacity between Ireland and Northern Ireland. Further to this physical / thermal limitation there are system stability contingencies (hazards) which increase with power flows in either direction e.g. a fault on the tie-line with high flows would lead to system separation, potentially breaching the	Operational Constraint (tie line limits) / Scheduling and Dispatch Decision (RoCoF mitigation)	Manual removal of non-performance difference charges would be required subject to the availability of supporting evidence/data which may not be available/conclusive. Review and complex analysis of events likely required.

		Operational Limit for Rate of Change of Frequency (RoCoF). As a result of these inter-area limitations an available unit which manages this contingency may be dispatched in preference for a unit which would exacerbate it.		
8.	Conservation of Energy Storage	To conserve impounded energy stores over a period e.g. hydroelectric and pumped-hydroelectric generator unit stores held back in expectation of tighter margins.	Scheduling and Dispatch Decision	Manual removal of non-performance difference charges would be required subject to the availability of supporting evidence/data which may not be available/conclusive. Review and complex analysis of events over a period of hours likely required.
9.	Hydroelectric Running Constraints	Environmental and hydrological constraints on hydroelectric facilities e.g. ramping limitations to ensure stability of reservoir structures, may result in hydro unit dispatch below availability.	Scheduling and Dispatch Decision (led by unit requirements)	Manual removal of non-performance difference charges would be required subject to the availability of supporting evidence/data which may not be available/conclusive.
10.	Observe Maximum On Time Limitations	When an online unit reaches its Maximum On Time (the maximum time that a unit can run following start up, per Technical Offer Data) it is shut down / de-committed while 'available'.	Scheduling and Dispatch Decision (led by unit requirements)	Manual removal of non-performance difference charges would be required subject to the availability of supporting evidence/data which may not be available/conclusive. Review and complex analysis of events over a period of hours likely required.
11.	Commercial Offer Data and Production Costs	Complex Commercial Offer Data (start-up, no load and incremental/ decremental price quantity pairs) is used in the scheduling process to determine both unit commitment status and indicative MW output levels across the scheduling horizon. The incremental price of an offline unit may be cheaper than an online unit however the start-up cost may be prohibitive in the context of the scheduling horizon. Whereas Simple Commercial Offer Data (incremental/decremental price quantity pairs only) is used for balancing actions and Imbalance Pricing.	Scheduling and Dispatch Decision (led by unit requirements)	Manual removal of non-performance difference charges would be required subject to the availability of supporting evidence/data which may not be available/conclusive. Review and analysis of events over a period of hours likely required.
12.	Synchronisation and Ramping Limitations	Synchronisation dispatch instructions ('Notice to Synchronise') observe a unit's hot, warm and cold state and associated start up times. An available offline unit may not be technically capable of synchronizing 'immediately' following an unforeseen event such as a	Scheduling and Dispatch Decision (led by unit requirements)	Manual removal of non-performance difference charges would be required subject to the availability of supporting evidence/data which may not be available/conclusive.

		large generator trip. Further, following synchronization, the unit will ramp up to its maximum availability over a period of time (observing unit ramp rates).		Review and complex analysis of events over a period of hours likely required.
13.	Generator Fuel Conservation	To maintain primary input fuel stocks (heavy fuel oil, distillate oil for ‘peakers’) e.g. if there are constraints on or risks to the supply of the input fuel.	Operational Constraint (if ‘must not run’ TCG is effective)	Manual removal of non-performance difference charges would be required subject to the availability of supporting evidence/data which may not be available/conclusive.
14.	Displacement by ‘Must Run’ Unit	Security of supply ‘must run’ constraints may be applied to a generator unit for a period of time e.g. due to the risk of a subsequent forced outage should the unit be desynchronised during a period of tight generation margins. The dispatch of other available units may be impacted by this ‘constrained on’ unit.	Operational Constraint	May be evident subject to configuration of Transmission Constraint Group in MMS i.e. SO flag may be available. Manual removal of non-performance difference charges would be required subject to the availability of the relevant SO flag. However the flag would be produced by the RTD scheduler which is not fully reflected in actual dispatch.
15.	Displacement by Cross Zonal Actions	System Operator trading over the interconnectors is initiated ahead of time in order to manage forecast system security risks and to maximise priority dispatch generation. The volume and duration of the trades are fixed in a revised interconnector schedule. Real time system conditions may vary compared with forecast conditions however and the revised interconnector schedule could displace available generation.	Scheduling and Dispatch Decision	Manual removal of non-performance difference charges would be required subject to the availability of supporting evidence/data which may not be available/conclusive. Review and complex analysis of events over a period of hours likely required.
16.	Conservation of Run Hours	Security of supply ‘must not run’ constraints may be applied to a generator unit(s) for a period of time e.g. due to limited run hours or starts remaining on a unit before a maintenance outage must occur. Conserving run hours during a period of low demand / high generation margins mitigates security of supply risks associated with periods of high demand / low generation margins.	Operational Constraint (if ‘must not run’ TCG is effective)	May be evident subject to configuration of Transmission Constraint Group in MMS i.e. SO flag may be available. Manual removal of non-performance difference charges would be required subject to the availability of the relevant SO flag. However the flag would be produced by the RTD scheduler which is not fully reflected in actual dispatch.
17.	Generator Reliability	A generator which is less reliable in successfully synchronising or which may take a number of attempts to reach stability may be started before a unit which has performed more reliably.	Scheduling and Dispatch Decision	Manual removal of non-performance difference charges would be required subject to the availability of supporting evidence/data which may not be available/conclusive. Review and complex analysis of events over a period of hours likely required.

18.	Environmental / Emissions License	Similar to the conservation of run hours for technical reasons, hours may be preserved due to emissions licence (e.g. SOx, NOx) limitations.	Operational Constraint (if 'must not run' TCG is effective)	May be evident subject to configuration of Transmission Constraint Group in MMS i.e. SO flag may be available. Manual removal of non-performance difference charges would be required subject to the availability of the relevant SO flag. However the flag would be produced by the RTD scheduler which is not fully reflected in actual dispatch.
19.	National Gas Supply Emergency (Ireland)	Per the CRU's National Gas supply Emergency Plan 2018 -2022, EirGrid 'will decide during a gas supply emergency, which power stations if required should fuel switch, reduce output or come off load'. Gas Networks Ireland would issue an 'instruction to EirGrid to co-ordinate reductions in gas demand for the gas-fired power generation sector'.	Scheduling and Dispatch Decision	Manual removal of non-performance difference charges would be required subject to the availability of supporting evidence/data which may not be available/conclusive. Review and complex analysis of events over a period of hours likely required.
20.	Non-Wind Priority Dispatch Plant	Non-wind Priority Dispatch units (hydro, peat, CHP) are generally dispatched to their Physical Notification (intended output and output level to which Priority Dispatch is applicable) and not above.	Scheduling and Dispatch Decision	Manual removal of non-performance difference charges would be required subject to the availability of supporting evidence/data. Review of events over a period of hours likely required.
21.	Dispatch of Minor Availability Increments	There may at times be small (<5MW) availability on a unit which remains un-dispatched for a period e.g. when the real time availability of a unit increases.	Scheduling and Dispatch Decision	Manual removal of non-performance difference charges would be required subject to the availability of supporting evidence/data. Review of events over a period of hours likely required.