SEM-23-047 Administered Scarcity Price Consultation

SSE response

Introduction

SSE welcomes the opportunity to provide feedback to SEM-23-047 Administered Scarcity Price Consultation. For the avoidance of doubt, this is a non-confidential response.

Who we are

SSE is the largest renewable energy developer, operator, and owner in Ireland's all-island Integrated Single Electricity Market. Since entering the Irish energy market in 2008, SSE Group has invested significantly to grow its business in Ireland, with a total economic contribution of €3.8bn to the State's economy over the past five years. We have also awarded over €9 million to communities in the past 10 years as part of our community benefit programme.

SSE is building more offshore wind energy than any other company in the world right now. We are currently constructing the world's largest offshore wind energy project, the 3.6 GW Dogger Bank Wind Farm in the North Sea, a joint venture with Equinor and Eni. This is in addition to Scotland's largest and the world's deepest fixed bottom offshore site, the 1.1 GW Seagreen Offshore Wind Farm in the Firth of Forth, a joint venture with TotalEnergies, which reached first power in recent weeks. In the most recent Scotwind process, SSE Renewables was awarded the rights, along with partners Marubeni Corporation (Marubeni) and Copenhagen Infrastructure Partners (CIP), to develop what will become one of the world's largest floating offshore wind farms off the east coast of Scotland.

We plan to bring our world-leading expertise in offshore wind energy to Ireland with plans to deliver over 3 GW of offshore wind energy in Irish waters, starting with our Arklow Bank Wind Park Phase 2 project off the coast of Co. Wicklow.

Through our SSE Thermal business, we continue to provide important flexible power generation. SSE's power station Great Island is Ireland's newest combined cycle gas turbine (CCGT) power station and one of the cleanest and most efficient on the system, generating enough electricity to power half a million homes. The acute need for flexible generation in Ireland has been demonstrated over the last twelve months, with EirGrid's most recent generation capacity statement showing that a shortfall in generation capacity was a significant risk this coming winter and for a number of winters to come, resulting in emergency measures being implemented by the CRU and Government.

While existing power stations continue to play a critical role on the system, SSE view the future of dispatchable thermal generation as being abated thermal, with Carbon Capture and Storage, hydrogen or other low-carbon fuels being the primary options. SSE have over 5 GW of zero and low carbon thermal under active co-development in the UK.

We will continue to evaluate opportunities to bring our expertise and investment in decarbonised flexible generation to Ireland, but it is vital that the state, Regulator and TSO provides an appropriate investment landscape to unlock such developments.

SSE Response

SSE welcomes the opportunity to provide a response to this consultation. We note that compared to the previous Administered Scarcity Price (ASP) discussion paper, this consultation sets out three specific options for changes to the Relative Scarcity Price (RSP) algebra, to take account of potential issues that may have blocked scarcity prices being triggered historically.

We are strongly supportive of the Electricity Association of Ireland's (EAI) response to this paper, and it contains many of the same concerns we raise below.

We have set out our consultation response in to two sections:

1. Comments to the options proposed.
2. General comments to scarcity design.

Comments to the options proposed.

Option 1

Option 1 proposes that the trigger of RSP should remove short term reserve. The rationale is that qSTR has been higher than qORR, and that short term reserve could be masking a higher likelihood of scarcity being triggered in the market. Historic analysis of system alerts was used to support this.

It is outlined in the paper that the ASP is an all-island trigger and is reserved for the Balancing Market (BM). In that case, it is entirely and wholly appropriate that the RSP contains in its calculation, short-term reserve. Since short-term reserve would be the most accessible reserve option in a short-notice market such as the BM.

It is also wholly reasonable that qSTR is higher than the qORR. This difference protects against any loss of the single largest in-feed and is an important supporting factor when considering wind intermittency. The current relationship between qSTR and qORR will not always be the case. The single largest in-feed is expected to increase over time with the connection of Celtic or the energisation of large CCGT sites in Northern Ireland. Therefore, over emphasis on the difference in these values at present and in isolation, is not useful and forgets the future changes which may well lead to a reversal of this situation. The paper in general does not model or consider the future impacts or interactions of the proposed changes especially where this change would have future (i.e., no retrospective) impact.

We believe that the intention with relation to option 1 is to try to identify if there are any dysfunctions in the design of the RSP that has meant that scarcity could be masked in the market. We do agree conceptually that there may be something limiting the triggering of the RSP in the first place. This conceptual issue is tied to the incentives (or not) the TSO has to utilise its reserves, the economic dispatch and economic trading that the TSO is incentivised to uphold, and how the dispatch of interconnectors is used at times of stress. We have stated before that there are no TSO incentives to help consider how they fully respond to scarcity.

There needs to be an acknowledgement that reserve is the last resort, because repeated triggering of scarcity does not show that reserve is in fact last resort. Especially, if some of this reserve is being proposed to be removed from the trigger calculation for qSTR, which will water down what reserve means. In this case, there needs to be clarity on what short-term reserve is useful for in the dispatch hierarchy. If the intention is for the scarcity signal to encourage storage to enter the market, the proposal to remove short-term reserve from the qSTR is effectively killing the market for these assets. As per the Scheduling and Dispatch programme of works, if batteries remain unable to participate fully in the SEM and their contribution to responding to scarcity would also be limited (as per Option 1), this would likely encourage market exit of these assets. The review of scarcity does not explain how batteries are expected to respond to scarcity (aside from providing reserve), if they cannot directly participate in the market yet.

It should also be considered how removal of short-term reserve and frequent triggering of scarcity will affect price takers like wind assets. The intermittency of such assets is supported through procurement and utilisation of reserves (and system services). As price takers, these assets would be affected by extremely high prices (especially if they were in imbalance), and there is no mechanism at their disposal to trade out their position, (since there has been no accommodation of their pricing priorities in the BCOP). Repeated triggering of the ASP is not a sustainable situation for price takers or price makers in the SEM and therefore, not suitable for customers either.

In our view this option will be ineffective for the problem that the SEMC may be seeking to resolve, i.e., that more scarcity events would trigger demand response, economic efficiency, and system security as well as investment signals. As indicated in the analysis, only historic modelling has been used. But a large majority of these system alerts were jurisdictional and where all-island system alerts were analysed, the analysis needed to go further back into history to 2021. The market dynamics now are very different from 2021 which was in the middle of the pandemic. The analysis is also isolated and does not think about the macroeconomics and broader energy landscape for the future including the effects of wind penetration, lower load factors for conventional units, more intermittent running of conventional units and more need for reserves to support wind intermittency.

The issue that the SEMC has with reserves potentially masking scarcity is not a unique problem to Ireland. The SEMC demonstrate this in considering other jurisdictions. However, none of these compared mechanisms really have the specific idiosyncrasies of the SEM, i.e., unit-based bidding, island system at the end of a gas network, interconnection with a third country, central dispatch, and a regulated cap at Reliability Option (RO) Strike Price (to motivate reliability) and a second trigger for reliability at ASP. Therefore, these comparisons are not a useful reflection of what could be possible in SEM.

For instance, it is true that where the price is allowed to freely settle at whatever price (like in the GB market, but not like the SEM which has the demonstrated market ceiling at RO Strike), this would more likely encourage merchant generators to enter the market. It would also be far more likely for merchant units to be attracted to a self-dispatch market, where response to scarcity and earning of scarcity rent is in the full control of the unit. None of these factors are features of the SEM design. It is also worth pointing out that in GB and Belgium, neither of their markets have experienced ASP events to date (even with more extreme market reactions in GB over the most recent period). Texas is even further removed as it does not have a Capacity Market. In Belgium, it also appears that their ASP mechanism is yet to be implemented[1]. Therefore, none of these case studies are comparable to the situation facing the SEM.

Options 2a and 2b

With respect to options 2a and 2b we note that both are considering the issue of constraints having an impact on scarcity. Our view is that constraints have an impact on scarcity being responded to. But not as a mask to RSP being in fact triggered more often. Rather considering constraints in this way could have the effect of causing scarcity not to be triggered in areas that require it, (this more applies to option 2b).

It is worth pointing out that SSE effectively demonstrated via Mod_02_21, that improper energy flagging was leading to system events affecting cash-out. It would be our view that the North-South tie-line is effectively a landlocked interconnector and a network asset and should also not be impacting on cash out. Network infrastructure should not influence pricing in the energy market. But it also cannot be solved by scarcity triggers in the market either. The impact of the North South Tie-line on cash out was demonstrated following market go-live. It could be addressed by other means but attributing it to a scarcity calculation is effectively suggesting that the energy market can solve network infrastructure issues. Which is not the case.

Regarding option 2b, this proposal further entrenches constraints in this market. In our view, all effort should be to reduce and remove constraints (as per Article 13), to implement inclusive, economic, and rational dispatch and scheduling, to deliver infrastructure development and benefits to units impacted by constraints. If we consider this further in the case of EU rules which will come to bear once Celtic goes live, it would be worth considering whether balancing rules in the EU would ever countenance constraints/network issues like this, being a reasonable trigger for scarcity. System issues like constraints being included as a trigger for scarcity would lead to all market participants facing punishing penalties when system limitations are outside their control to remedy. This is not the principle on which Mod_04_23 is based, where system impacts are placed outside influencing generator penalties. On that note, we would consider that the outcome of implementing of EBGL would have an impact on how balancing actions and scarcity could be treated in the SEM, which has not been considered in the proposals to support changes to the RSP trigger.

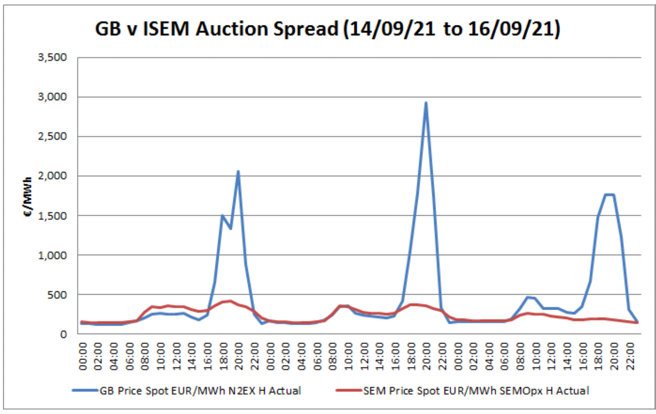
[1] CRM-Monitoring-Report-Belgian-electricity-market-Implementation-plan-2022.pdf (fgov.be)

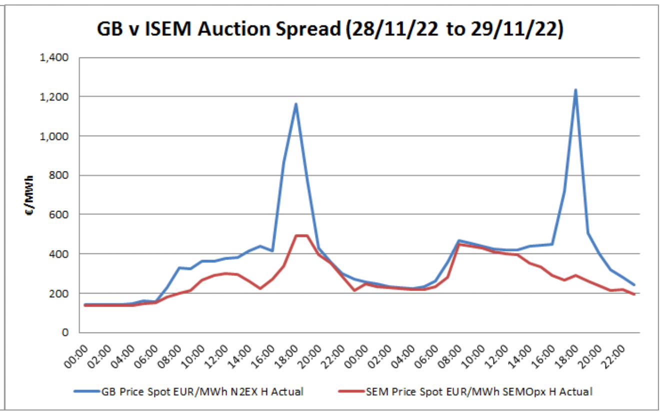
General comments to scarcity design

Below we have outlined additional comments regarding the scarcity design outside of the specific options proposed, but more responding to the approach and principles underpinning this consultation.

1. The scarcity mechanism is by its design a short-term reactive mechanism in the BM. This makes this market signal rightly, a temporary one. A single, temporary, opportunistic revenue signal like scarcity rent, even if triggered frequently, (which is wholly inappropriate), would therefore not be a sufficient long-term signal to support a business case for a 15-30-year investment in a generation asset (or even a shorter-term investment in storage since as above, there are limited market options for storage participation). It is unrealistic to consider that a short-term mechanism like ASP would be a reasonable signal on which to make sustainable and enduring investment (and on which basis, shareholders and lenders would be expected to approve). ASP does not create an investment signal and it increases the risk of holding a capacity contract given how strongly the RO incentive drives market behaviour.
2. It has never been evidenced what amount of non-RO holders are expected to be encouraged by a short-term RSP signal in the BM. The SEM to date is clearly not sufficient for merchant units to enter, (otherwise the CRM and RESS would not be so necessary). Once reserves are drawn down and Replacement Reserve is exhausted (which we expect is the order of dispatch that would lead to a full triggering of ASP), there are clearly no significant volumes of capacity capable of responding above the RO Strike once all other assets have responded that can.
3. Scarcity is directly related to the Reliability Standard and the Value of Loss of Load; both of which are still due for consultation by the SEMC. Similarly, EBGL, CACM, reconnection with Europe via Celtic, the size of Celtic as single largest in-feed, would all have a direct impact on how RSP operates and how scarcity may be addressed in future. All of these have an impact on the rationale and principles of this paper. The overwhelming fact is that scarcity cannot be viewed in isolation and cannot be viewed simply mathematically to multiply the frequency of scarcity events. It must be reviewed in the context of all these directly related policy, regulatory and compliance projects over the coming 5 years.
4. It is wholly disproportionate to trigger RSP more often, simply because it has never occurred. Market signals and regulatory framework currently do not encourage or incentivise pricing above the RO Strike Price irrespective of the changes being proposed (which are theoretical and do not fully take account of the realities of the operation of the SEM). We have the following concerns:
    a. **Protection of customers:** It is signalled that ASP triggering will better protect customers. The consultation also clarifies that in fact customers are protected from high prices from the start of the RSP. Therefore, more triggering of the ASP cannot be better protecting customers if there are already protected from price exposure. Higher prices where industry have been clear that there is already an existing price limitation in the RO Strike Price, cannot be said to be proportionate for the protection of customers. Higher prices in this market also means higher collateral posted by participants to manage higher risk. This means a risk of bigger losses and bigger impacts to customers. The market should not be seeking to normalise this degree of panic when there is a cost-of-living crisis.
    b. **System security:** It cannot be the view the scarcity would succeed where the CRM has failed in delivering new enduring capacity for the purpose of security of supply (which was the rationale for the CRM mechanism). One mechanism produces a long-term signal (CRM), the other is temporary and produces a short-term signal (ASP). Pushing for scarcity to be another signal for legitimate system security, risks undermining the whole rationale for the CRM.
    c. **Stop loss limits:** Whilst this may be perceived as a limit to generator exposure, it does not provide sufficient protection or risk mitigation for the other barriers to pricing above the RO Strike Price. This is a strongly collateralised market. Higher prices at scarcity mean higher collateral also needs to be posted to protect against higher losses. This means much more costs being carried than simply at the Stop Loss Limit.
    d. **RO strike price effect:** Actual market behaviour demonstrates consistently that prices collect below the RO Strike Price on both sides of the trade, reflecting that it is acting like a ceiling (or regulated cap), rather than being a theoretical floor for RSP. This can be seen even when compared to GB when both markets were suffering from high stress (see figures below). Where

some units may have offered above the RO Strike Price, it's seen that at that level, supply does not clear because the prices are too high and there is no incentive for suppliers take higher prices. Suppliers' risk is rightly protected by the Socialisation Fund, but this creates at the same time, no incentive for higher priced generation to be bought. The RO Strike Price incentivises both generation and supply to participate under it. This is beneficial to customers, but it is not appropriately considered in this paper.





e. **Regulatory pricing risk:** ***"****Scarcity pricing is the principle of pricing electricity at a value above the marginal cost of the marginal unit during conditions of high system stress, according to the incremental value that flexible capacity offers to the system in terms of keeping the loss of load probability in check*[2]*."* Market revenues in SEM are defined based on the recovery of Short Run Marginal Costs. Whether bids are taken as simple or complex, SRMC and scarcity cannot be quantified as existing within the same boundaries. Bidding Principles (BCOP) do not contain any provisions for scarcity rent to be priced in the market in such a way that it would be acceptable and not potentially scrutinised as cost unreflective (under a generator's licence). This creates regulatory and enforcement risk for market participants if they choose to price at the extremes, (this was evident at the start of the market where outlier pricing was reined in through TSC modifications). This has not been considered in this or previous papers relating to the concept and application of scarcity.

5. Finally, the paper states, *"Ultimately, this [not having ASP triggered] has a negative impact on consumers given that unit unreliability decreases the surplus/increases the deficit in the adequacy assessment conducted by the Transmission System Operators (TSOs), which may increase the volume of capacity to be procured through the CRM and paid for by consumers. An appropriate RSP trigger, which promotes reliability, can therefore help to reduce costs in the long-term for consumers."* This assumption is concerning. De-rating factors in the CRM design already account for unit unreliability and these de-rating factors are adjusted over time to reflect how unreliability also changes. This must be factored into the SEMC's assumptions about generator availability. From a commercial perspective, generators seek to be on outage for as short a period as possible because those hours on outage represent time when revenue cannot be earned, and generation cannot be offered to meet demand. The reference above suggests that customers are perceived to be impacted simply because unit unavailability skews the adequacy assessment the TSO calculates. Industry and SSE have been vocal before that the Reliability Standard, LOLE and other adequacy metrics are improperly applied, and we await consultation on these. Furthermore, as above, de-rating factors are well-used in the CRM and should be a reasonable factor in assessing adequacy.

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[2] Scarcity Pricing simulation (elia.be)

Units must also adhere to the requirements of their OEMs and schedule regular outages to ensure the best operation, efficiency, and safety of their stations, so that they can continue to provide generation to meet demand. This has not been clearly acknowledged as a reasonable and responsible activity to ensure safe and secure supply. Throughout, and in previous consultation responses, we have been clear that unit reliability is appropriately incentivised through the RO Strike Price mechanism. It is unreasonable to signal unit reliability (rather than repeated failed capacity delivery), as a reason for CRM capacity requirements being high. Especially, when we have seen the Capacity Requirement under the CRM continue to fall, rather than rise as would be expected given repeated contract terminations.

In addition, Grid Code and associated OSC charges contain additional obligations and incentives for units to return when under test, when on forced outage, after an unplanned trip; as soon as reasonably practicable. It cannot be entertained that there is a view that unit unreliability needs yet another penalty to incentivise response. There are plenty of penalties and charges already embedded in SEM design.