Single Electricity Market

(SEM)

Information Paper on Scarcity Pricing and Demand Response in the SEM

SEM-21-083

4 November 2021

EXECUTIVE SUMMARY

On 26 May 2021, the Regulatory Authorities (RAs) published a Discussion Paper and Call for Evidence on Scarcity Pricing and Demand Response in the SEM. The aim of the Paper was to identify measures, if any, that could be implemented on an interim basis for Winter 2021/22, to encourage both the formation of appropriate price signals during times of scarcity and demand side response to those signals. This is in the context of expected tight capacity margins during the Winter of 2021/22 and other potential options being explored with the TSOs to mitigate these.

Fourteen responses to the Discussion Paper were received and the purpose of this Information Paper is to provide an overview of responses and outline the next steps the RAs intend to progress in this area, also considering other publications and developments regarding security of supply since the Discussion Paper was published. Further background information can be found in the Discussion Paper itself (SEM-21-042).

Section 2 of this Paper provides an overview of responses received in relation to changes to the Reserve Scarcity Pricing trigger and curve. Overall, respondents are of the view that changes in this area would increase regulatory uncertainty for both existing and future Capacity Market contract holders and undermine market and investor confidence in the Capacity Market. The majority of respondents also note that any changes in this area would not bring immediate or useful signals at such short notice, with generation already incentivised to be available through the Capacity Market. The RAs acknowledge in particular the practical difficulty of implementing any changes in this area to be effective by Winter 2021/22. The RAs are of the view however that the interaction between Reserve Scarcity Pricing, the Reliability Option Strike Price and prices in the ex-ante and balancing markets during periods of tight generation capacity margins is an area which merits further consideration in the future.

Section 3 outlines the feedback received in relation to implicit demand response and existing incentives for demand-side flexibility in the energy and capacity markets through Demand Side Units. The RAs recognise the importance of implementing an enduring approach to energy payments to DSUs and this workstream is therefore being prioritised, with further engagement with DSUs, industry bodies, the TSOs/ Market Operator and other key stakeholders expected in the short term.

A number of areas of potential improvement have been identified in terms of information provision regarding System Alerts and capacity margins and the RAs will engage with the TSOs based on the areas highlighted in Section 4.3 of this discussion paper with regard to improvements that can be progressed.

All non-confidential responses are published with this Information Paper.

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1. Introduction

1.1 Overview of Discussion Paper

On 26 May 2021, the Regulatory Authorities published a Discussion Paper and Call for Evidence on Scarcity Pricing and Demand Response in the SEM. The aim of the Paper was to identify measures, if any, that could be implemented on an interim basis, for Winter 2021/22, to encourage both the formation of appropriate price signals during times of scarcity and demand side response to those signals.

The Discussion Paper considered the implementation of administered scarcity pricing in the revised SEM arrangements to date. The administered scarcity pricing mechanism involves moving energy prices above the cost of the marginal unit under conditions where the system is short on generation capacity and reserves, in order to incentivise demand response and generation capacity capable of providing reserves to the system and enhance Capacity Market performance incentives. In the SEM, the Reserve Scarcity Price (RSP) applies as soon as available capacity is less than that required to cover electricity demand plus the associated operating reserve requirement. This sets a price floor at times of system stress to reflect the cost of scarcity, which is equal to the Reliability Option Strike Price. In the Trading and Settlement Code, RSP applies when the available Short Term Reserve Quantity (qSTR) is less than the Operating Reserve Requirement Quantity (qORR).

The Discussion Paper also discussed how to facilitate greater levels of implicit and explicit demand response for Winter 2021/22. Feedback was sought from stakeholders, consumers, suppliers and DSUs on both the effectiveness of existing incentives and the potential for increased incentives for demand side participation, as well as on the value of giving advance notice of tight capacity margins or the conditions which might lead to system alerts.

1.2 Security of Electricity Supply

While it was not raised as part of the Discussion Paper, a number of responses referenced temporary generation to be procured in the Dublin area for Winter 2021/22. Respondents requested clarity on how these contracts will be remunerated and what their impact will be on market prices and positions.

The CRU has since published a number of recent directions to EirGrid and GNI in support of electricity security of supply in the medium and short-term which can be found here and provide further information in this regard.

On 29 September, the CRU also published an Information Paper (which can be found here) on the short-term security of supply risks for the forthcoming winter 2021/22 and the programme of actions that the CRU, in line with its statutory duties, is undertaking in cooperation with EirGrid, DECC, the energy industry and other stakeholders. These actions include the procurement of additional temporary emergency generation capacity as referenced by respondents to the Discussion Paper. The paper notes that the delivery of temporary emergency back-up generation is not feasible in the required timeframe, even on a fast-tracked basis. The Huntstown 2 and Whitegate power plants are anticipated to come back onto the system in October and November, returning approximately 800MW of gas-fired capacity to the system, which mitigates the security of supply risk for this winter.

Eirgrid and SONI have also published the All-Island Generation Capacity Statement 2021[1] and the Winter Outlook[2] for 2021/22, providing information on the reduced capacity margin due to increasing demand, closure of dispatchable generation plants and increased generator forced outage rates over time. The Winter Outlook notes the risk of System Alerts over the winter period if high generator forced outage rates continue, particularly during times when renewable generation is at a low output and support is not available from Great Britain across the interconnectors.

[1] https://www.eirgridgroup.com/site-files/library/EirGrid/208281-All-Island-Generation-Capacity-Statement-LR13A.pdf

[2] https://www.eirgridgroup.com/site-files/library/EirGrid/Winter-Outlook-2021-2022.pdf

2. Administered Scarcity Pricing

2.1 Areas raised in Discussion Paper

In the Discussion Paper, the RAs discussed the trigger for Administered Scarcity Pricing (ASP) in the SEM and whether it should be made more sensitive and made to align more closely with the triggers for System Alerts, such that when a System Alert is issued it would be more likely that ASP would apply.

The Reserve Scarcity Price in the SEM applies as soon as available capacity is less than that required to cover electricity demand plus the associated operating reserve requirement. It is intended to provide capacity providers and suppliers with early incentives to react to scarcity, reducing the likelihood of further adverse events such as load shedding. As currently implemented within the Trading and Settlement Code, Reserve Scarcity Pricing (RSP) applies when the available Short Term Reserve Quantity (qSTR) is less than the Operating Reserve Requirement Quantity (qORR). The RAs considered whether the trigger for RSP should be amended such that the qSTR would include only Tertiary Operating Reserve Band 2 and not Replacement Reserve, or whether another amendment could be made that would bring this trigger more into line with the triggers for System Alerts in the SEM in order to provide earlier price signals for scarcity.

The RAs also discussed whether the starting point of the Reserve Scarcity Price (RSP) curve should be changed so that the minimum price would be either higher or lower than the Reliability Option strike price, and additionally, whether the maximum price on the curve (the Full Administered Scarcity Price (FASP)) should be a higher percentage of the Value of Lost Load than it is currently. Feedback was sought from stakeholders on these considerations.

Respondents' views were invited as to whether:

a) the trigger for RSP should be amended such that the qSTR would include only Tertiary Operating Reserve Band 2 and not Replacement Reserve, or whether another amendment could be made that would bring this trigger more into line with the triggers for System Alerts in the SEM.

b) the RSP curve should begin at a point above or below the RO Strike Price.

c) the FASP value should be increased to a level closer to 100% of VoLL.

Feedback was also sought in relation to alternative delivery incentives during times of system stress which could be implemented in the short term.

2.2 Responses Received in relation to RSP Trigger

A number of respondents noted that it would be difficult to alter the conditions of ASP for any existing capacity contract where such contracts were tendered for under the current ASP conditions. In their view, this would increase regulatory uncertainty for both existing and future Capacity Market contract holders and undermine market and investor confidence in the Capacity Market. This could increase risks of unintended exit and defer investment which is acutely required.

The majority of respondents were of the view that any changes in this area would not bring immediate or useful signals at such short notice with generation already incentivised to be available through the Capacity Market.

A number of individual points raised by respondents are set out below:

- While EirGrid and SONI agree that it is appropriate to examine the system conditions where System Alerts have occurred in order to assess whether RSP not having been triggered was appropriate, in their view further analysis of the impact of any changes being considered on Dispatch Balancing Costs, bidding levels in future Capacity Auctions and Difference Payments and Charges should be carried out. They have also advised that there would be a lead time to implement any interim changes in this area and that it may be appropriate to consider longer term enduring changes.
- ESB GT note in their response that since the beginning of the revised market arrangements, there have been no scarcity events where there has been a lack of reserve provision. Where system tightness has occurred, it has typically been in one jurisdiction only.
- Energia state that in 2020 and 2021 only two System Alerts occurred related to system wide capacity issues and it would not be appropriate to link a SEM price to localised capacity issues. In all cases surpluses of capacity were available and during two System Alerts exports from SEM to GB were maintained. On this basis, it would be inappropriate to align the trigger for ASP to System Alerts. In Energia's view, any intervention to create higher prices during System Alerts will not result in any more generation being available as generators are already incentivised to be available at all times.

- EAI are of the view that it is flawed to align the scarcity pricing mechanism to System Alerts and that it will not solve the underlying concerns raised. They state that the issues outlined in the paper are a result of underestimation of capacity requirements for successive capacity auctions, as well as a withholding of capacity given uncertain demand. Linking ASP to Amber Alerts could trigger higher prices even when there is a large capacity surplus and removing Replacement Reserve from the calculation could give rise to ASP pricing caused by TSO scheduling and operational decisions.
- Bord na Mona state that there have been a number of RO events where generators were available but not dispatched and subject to Difference Payments, which could increase if the frequency of ASP is increased. Bord na Mona also note that information has not been provided to show that existing capacity is not responding during Amber Alerts, with the lack of existing capacity in terms of MWs to respond being the primary issue.
- PrePayPower note that the majority of System Alerts to date have been jurisdictional and due to the system constraint of insufficient power transfer capacity between ROI and NI. It would not be appropriate to impose a system wide price change to a localised constraint, which would only be appropriate in a Locational Marginal Price based market.
- PPB do not support the changes proposed and are of the view that such measures would only increase exposures for existing participants. PPB has noted that while forced outage rates are high, these are not unexpected and will increase as conventional units stop and start more regularly. In their view, the use of low forced outage rates in the determination of the capacity requirement is a significant issue.
- In FERA's view, the idea that ASP will help with additional generation or demand side response should be challenged, as if it does not exist it will not turn up, despite the price.
- SSE are of the view that ASP should only trigger at a time of reserve scarcity, where the volume of short-term reserves is less than required, which has not occurred to date under the new SEM arrangements.
- While WEI and RNI members agree with the need for immediate action to address security of supply issues, they do not believe that amending Administered Scarcity Pricing with such short notice will give a constructive signal to market participants. ASP mechanisms can be used to signal short term flexibility or as a long run signal for new investments, but participants cannot respond to ASP changes with such short notice, especially to bring on new investments to maintain system adequacy. As the SEM is a

centrally dispatched market, generators also cannot provide flexibility in response to real time ASP pricing.

- DRAI do not support proposals that seek to modify ASP during already procured capacity years given the impact this could have on future capacity market bids and the assumptions behind long-term fixed price hedging arrangements between suppliers and end customers. In addition, they consider that the discussion paper fails to acknowledge that spurious market price volatility has also occurred outside of periods associated with capacity margin shortages.
- BGE does not agree that there is an immediate security of supply benefit to be gained from aligning ASP triggers with amber alerts or from altering the price points on the ASP/RSP price curve.

2.3 Responses Received in relation to RSP Curve

- EirGrid and SONI note in their response that changes to the RSP curve start point may not be beneficial given that the triggers for RSP and the Full Administered Scarcity Price (FASP) have not been met to date.
- In relation to any change to the RSP curve or the level of the FASP, ESB GT states that such changes should only be considered for capacity contracts yet to be tendered for.
- Energia do not believe that sufficient justification has been provided to move the RSP curve away from its current starting point to either above or below the RO strike price or to increase the current level of FASP to 100% of VoLL.
- EAI is of the view that the proposals regarding the FASP being aligned to VoLL should be considered along with the expected review of VoLL to be carried out by the RAs.
- Bord na Mona state in their response that the level of FASP was initially set in recognition of the lack of a functioning secondary trading capacity platform, which would provide a method of risk mitigation.
- PrePayPower have concerns regarding the impact on consumers if scarcity pricing were invoked earlier in the price curve as it could lead to price rises in the Day Ahead Market.
- SSE is of the view that the Scarcity Curve is currently set at a suitable level to reflect the price of reserve scarcity. In their view, the lack of demand responsiveness during high prices or negative prices indicated that any adjustment in this area is unlikely to bring about behavior change. In addition, the overall level of the ASP at present

recognises the lack of secondary trading which was to be implemented post I-SEM go-live.

2.4 RA Considerations

The RAs acknowledge the points raised by respondents to this section of the discussion paper and in particular note the practical difficulty of implementing any changes in this area to be effective by Winter 2021/22 due to the requirement for system changes and a lead time associated with implementation of any change to RSP. The RAs welcome the feedback provided by respondents and the views raised regarding the effectiveness of such changes in addressing system adequacy issues.

Following consideration of the responses received to the Discussion Paper, the RAs do not intend to proceed with a Consultation on changes to Reserve Scarcity Pricing for Winter 2021/22. In the RAs' view, it would be useful to carry out further assessment of RSP in order to further understand the impact of any changes relating to:

- Incentives and prices during times of scarcity.
- The effectiveness of RSP and ASP to date.
- Impacts of changes in this area on Dispatch Balancing Costs, bidding levels in future Capacity Auctions and Difference Payments and Charges.

As highlighted in a number of responses, there are a number of ongoing areas of work which are also relevant to the considerations here. As these areas progress the RAs will consider the functioning of RSP further.

FASP is currently set at 25% of VoLL, with the current value of VoLL used in the SEM set in 2007, at €10,000/MWh. This has been indexed annually since and the value used for the most recent Capacity Auction (T-4 2024/2025) was €12,533. Regulation (EU) 2019/943 of the Clean Energy Package requires the calculation of VoLL based on consumer surveys and a methodology for this has been developed by ACER[3]. The RAs have commenced the process to conduct surveys in this area with domestic and non-domestic electricity customers, aligned to the ACER methodology.

Responses to the recent Consultation on SEM compliance with the Guideline on Electricity Balancing were received on 14 June 2021 and the RAs are currently considering responses

[3]https://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Individual%20decisions/ACER%20Decision%2023-2020%20on%20VOLL%20CONE%20RS.pdf

received. The compliance of Administered Scarcity Pricing in the SEM with Article 55 of EBGL, which relates to rules for calculation of the imbalance price, will be considered further in this context and may bring about changes in this area.

In terms of the responses received in relation to Secondary Trading, an interim solution was put in place to enable Capacity Market Units (CMUs) to suspend their Reliability Options (ROs) during Planned Outages by providing an Interim Secondary Trade Notification (ISTN) to the System Operators (SOs). Further to this, Alternative Secondary Trading Arrangements, prior to an enduring set of arrangements, were put in place in 2020 and the status of these arrangements will be taken into consideration in the context of any future changes to the level of FASP.

In relation to pricing in the ex-ante and Balancing Markets during times of system tightness, the RAs have observed that during recent System Alerts, for example in September 2021, prices have risen in the DAM and IDA1 in GB to reflect tight capacity margins while in the SEM prices have remained below the level of the Reliability Option Strike Price[4], with interconnector flows set based on the IDA market results and prices on both sides of the interconnectors between the SEM and GB (accounting for NTC values, interconnector ramp rates and loss factors). This has resulted in market scheduled exports from the SEM to GB during times where such exports are not feasible due to security of supply or physical constraints in the SEM. Figures 1 and 2 demonstrate these price spreads between the SEM and GB in September.

[4] An update was issued by SEMO under Section F.16.2 of the TSC on 6 October 2021 in relation to the calculation of the Strike Price, which increased from €500 to €739.55 driven by a higher Gas futures input price for the month of October. The indicative Strike Price has been calculated by SEMO for November 2021 as €539.01.

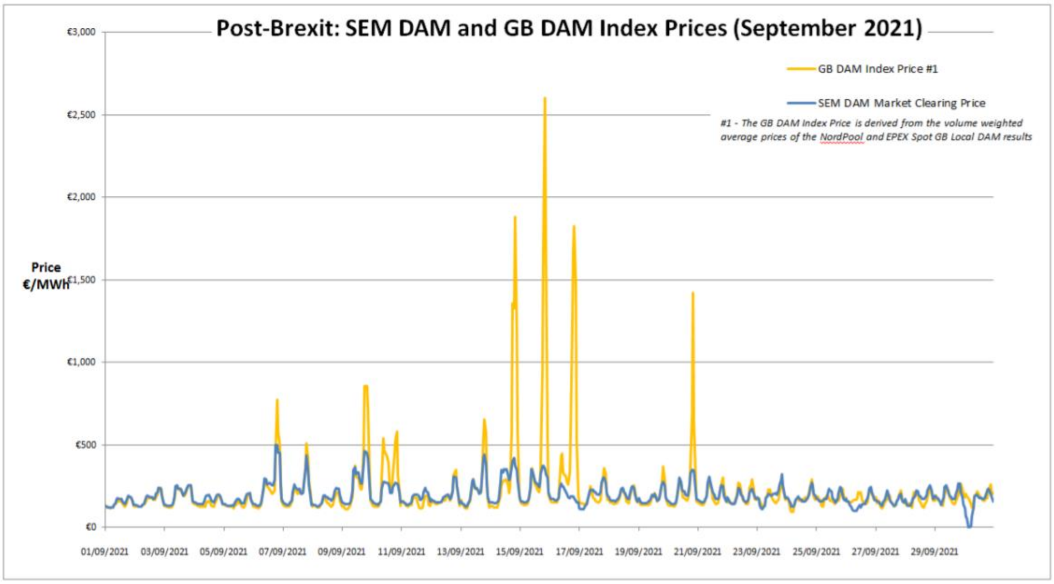

Figure 1[5]

An All-Island System Alert occurred on 6 September, with a System Alert for Ireland on 9 September and for Northern Ireland on 12 September. During these times, generation margins were also very tight in GB.

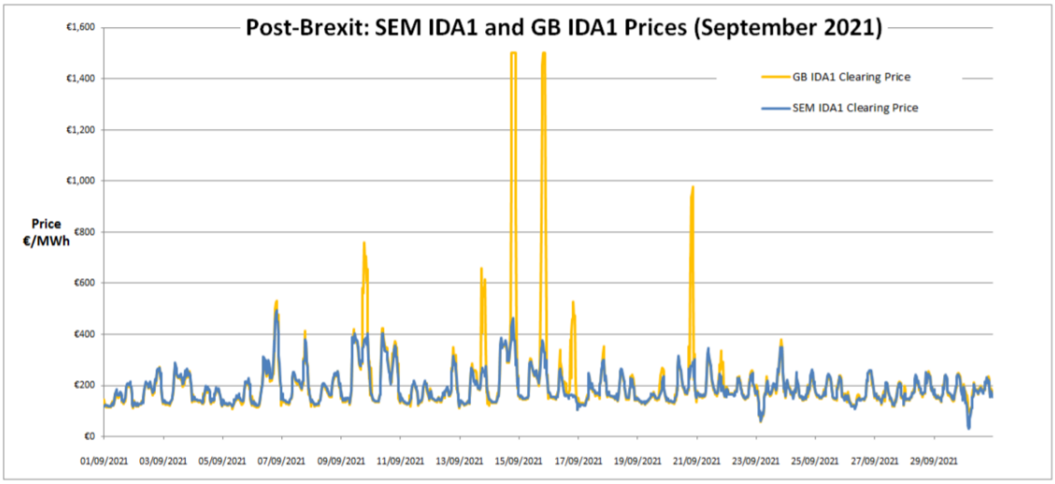

Figure 2

The overall interaction between Reserve Scarcity Pricing, the Reliability Option Strike Price and prices in the ex-ante and balancing markets during periods of tight generation capacity margins is an area which merits further consideration in the future.

In relation to responses highlighting current incentives for generator availability and situations where capacity market generators are available but not dispatched and subject to Difference

[5] From 14 October 2021 Market Operator User Group Presentation; https://www.sem-o.com/documents/general-publications/Market-Operator-User-Group-Presentation-14-October-2021.pdf

Payments during RO events, the Regulatory Authorities are aware that a number of proposed related Modifications are being considered through the Balancing Market Modifications Committee. This issue has impacted on a number of generator types, including Demand Side Units.

3 Demand Response

3.1 Areas raised in Discussion Paper

Implicit Demand Response

The RAs also sought feedback on options which could be implemented in the short term to encourage greater levels of implicit demand response prior to and during System Events. During the CRM design phase, the SEM Committee stated that stronger incentives were needed for suppliers to negotiate demand response agreements with a wider range of customers with half hourly metering, based on the limited amount of price sensitive industrial load in the SEM.

Feedback was requested from relevant stakeholders on:

- The response of large energy users to price signals in the wholesale market.
- Supplier interaction with incentives for demand response in the wholesale market.
- The extent to which suppliers and customers can be incentivised to reduce demand where prices are above the RO Strike Price, given that the supplier hedge applies above this price.

Explicit Demand Response

Feedback was sought on how existing incentives for demand-side flexibility in the energy and capacity markets through Demand Side Units could be improved through interim changes. The interaction between the areas considered in relation to ASP and incentives for DSU energy payments was considered and feedback was requested from relevant stakeholders on:

1. The strength of the existing incentives for DSU availability and the effect of the potential changes to ASP proposed on these incentives.
2. Additional short-term incentives which could encourage further DSU availability.

3.2 Responses Received

An overview of respondent's views is provided below:

- In Energia's view, much of the demand which might be price responsive is already captured under DSUs and there is insufficient flexibility to respond to pricing signals, with customers insulated from short term price events. Suppliers attempt to mitigate the risk of high BM prices through trading the majority of volumes in the ex-ante markets. Over 450MW of DSU capacity has also already received contracts for CY-21/22 and proposals to sharpen the penalty for being unavailable after contracts with underlying customers have been struck will not create additional response.

- EAI note that the intention of the paper's proposals is centered around addressing the expected security of supply risk this winter with demand side response. However, they consider that demand side response has been untested as a mechanism to mitigate security of supply and without evidence of outcomes this is not a suitable approach to address expected security of supply risk.
- PrePayPower are of the view that DSUs may price themselves in a way in which they will rarely be called to run, by pricing relative to the cost of interrupting processes and the risk of being dispatched. If the changes proposed to scarcity pricing were introduced, DSUs would increase their price to maintain the same relative risk of dispatch. Measures to bring more demand response into the market cannot be introduced in such a short period but should be considered over longer time frames.
- PPB are of the view that any incentives on DSU availability should not distort the market as each MW of capacity should have equal value.
- FERA state that for Suppliers to be interested in higher market prices, the RO scarcity trigger value would need to be increased, such that they and their customers would be exposed to additional costs. In terms of demand side response, it is difficult to incentivise additional service provision as DSUs are not paid for the provision of energy. In their view, energy payments would incentivise DSUs to provide above the RO level.
- SSE states that the proposed approach to adjusting regulatory levers would not directly affect parties with interruptible contracts and would be unlikely to encourage behavior change for contracted units.
- In relation to large energy users, DRAI understands that most procure power on an ex-ante basis and hedge against prices, with minimal exposure to the Imbalance Settlement Price. DRAI question the focus on short-term incentives which could encourage further DSU availability in the absence of similar queries around interconnection in terms of interconnector exports during capacity events. In terms of concerns around DSU availability, the DRAI states that it is important to understand how the market currently fails to provide DSUs with an incentive to be dispatched. DSUs do not have a market incentive to maximise availability, as such incentives are absorbed by the supplier contracted for energy at the site. Individual Demand Sites

(IDSs) are disincentivised from making volumes available in excess of the load following adjusted awarded volume due to increased exposure to costs when dispatched. The introduction of energy payments for DSUs addresses this market failure. In their response, DRAI propose two solutions to enable aggregators to incentivise increased participation by customers in the short-term. However, they emphasize that the timelines for implementing these solutions are extremely challenging for Winter 2021/22 and that it may be more realistic to assume an associated increase in performance across entire portfolios for Winter 2022/23.

    1. The first proposal is to amend or temporarily suspend the BCoP for DSUs, as where this forces bids below the strike price, it exacerbates the extent to which costs must be absorbed by participating businesses and fails to allow for disruption to businesses participating as part of a DSU. Where aggregators cannot ensure their full cost of dispatch can be recovered, it makes it difficult to ensure high availability declarations for individual customers.
    2. The second proposal is to revise the current interim arrangements for DSU energy payments to lower the threshold above which energy payments are made to DSUs in order to encourage increased performance from IDSs.

- Bord Gais Energy suggest in their response that steps should be taken to minimise barriers of demand sites switching between DSU providers in order to enhance the volume of demand side response. Once a demand site has been tested and is assessed by the TSO as qualified to participate in a particular DSU provider, if that site then seeks to switch to another DSU provider (which has itself been tested and qualifies to provide system services for example) minimal if any 'retesting' of the site should be required. Bord Gais Energy is also of the view that the consultation on the enduring solution for DSU energy revenues should be brought forward to enhance the scope of DSU energy revenue earning.

3.3 RA Considerations

The RAs welcome the further information provided by respondents in terms of implicit demand response and the suggestions to improve incentives for DSU availability. These include:

1. Implementation of an enduring solution for DSU energy revenues.
2. A proposal to revise the current interim arrangements for DSU energy payments.
3. Amendment of the BCOP for DSUs.
4. Review of process for demand sites switching between DSU providers.

In terms of energy payments for DSUs, an interim approach through Mod_17_19 has been implemented to ensure compliance with State Aid requirements in the short term. The Demand Side Unit (DSU) state aid compliance decision paper (SEM-19-029), decided that initially energy payments for DSUs, arising from dispatch in the balancing market above ex-ante position, would only be made at times when DSUs are required to pay difference charges. The SEM Committee decision in this area set out a high-level principle for an enduring approach which provides for more complete participation of DSUs in the energy markets in line with Clean Energy Package requirements. This will involve energy payments being made to DSUs at all times, once a number of issues are addressed such as the link between dispatched quantities and metered quantities for DSUs, the effective operation of the socialisation mechanism and the method for accounting for the Metered Quantity of DSUs in settlement.

The RAs recognise the importance of implementing the enduring approach to energy payments to DSUs and as explored in the Discussion Paper are of the view that this provides important incentives in the energy market. This has been raised as a significant issue through both the responses received to the Discussion Paper and separate engagement with the Regulatory Authorities. This area of work is being prioritised by the RAs and a project has commenced to progress an enduring solution, with further engagement with DSUs, industry bodies, the TSOs/ Market Operator and other key stakeholders expected to commence in the short term.

In terms of any revision in the short term to the current arrangements to DSU energy payments, the RAs understand that the proposal from DRAI is to implement changes to the current approach in Mod_17_19 (where energy payments are made to DSUs if any traded volumes are exposed to Difference Charges and where unit's bid prices or the imbalance price are above the Strike Price), in order to provide energy payments above a revised threshold that is lower than the current Strike Price. The RAs have discussed this approach with the TSOs and understand that this would involve system changes to introduce a new parameter (via a price which is different to the Strike Price) and would involve a lead time for the design of new settlement logic.

Another approach which has been discussed separately with DSU representatives concerns a potential interim arrangement which provides energy payments to DSUs reflecting a calculated value of the avoided cost of energy during times when demand is reduced.

While the RAs consider that these approaches suggested by DRAI may be worth consideration in the context of an enduring solution, the RAs are concerned that they would not address many of the issues highlighted in SEM-19-029 relating to measurement of delivery of demand response, supplier costs and settlement of demand response volumes.

The RAs also note in this context the DRAI's view that increased performance across entire portfolios as a result of a change of this kind may more realistically be assumed for Winter 2022/23 rather than Winter 2021/22. On balance, and having considered respondents' comments, the view of the RAs is that the focus of incentivising explicit demand response should be on the development of an enduring solution for energy payments to DSUs and that this should be progressed as soon as possible.

Seeking to implement an alternative interim solution in the meantime would divert time and resource from the enduring solution and would be of doubtful benefit for Winter 2021/22. In addition, the RAs are not of the view that it would be appropriate to consider changes to the application of the BCoP for any specific type of market participant at this time.

DSUs are required to demonstrate Grid Code compliance before becoming operational, through a number of Grid Code compliance tests which take a number of weeks. Where an Individual Demand Site (IDS) aims to switch between DSU Operators, the DSU which the IDS intends to transfer to is required to submit an application form[6] with standard timelines for TSO assessments, for example to check adequate communications with the relevant control centre. IDSs seeking to transfer registered characteristics between DSUs are also required to complete a 'Statement of Intention to Transfer' form[7]. While the RAs acknowledge that improvements could be considered in this area, such changes would at this stage be unlikely to result in increased explicit demand response in time for Winter 2021/22.

In relation to further incentives for new DSU capacity, a recent Modification Proposal was raised to amend the Capacity Market Code in relation to the provisions for Substantial Financial Completion for Awarded New Capacity in the Capacity Market. This Modification was the subject of engagement between the RAs and DSU representative bodies, as part of a number of areas being considered to improve demand side flexibility in the SEM. This aims to provide for a modified process for DSUs/AGUs to progress Financial Completion in order to account for the differences between Awarded New Capacity delivered by a DSU / AGU compared to other unit types.

New demand sites being brought into a DSU / AGU typically only require the installation of communications and control equipment to enable remote dispatch. With existing grid connections, generators and/or on-site loads already fully operational, this process can be completed in a number of weeks, a significant difference versus other unit types which require major construction projects with long timelines to deliver New Capacity. This Modification

[6] http://www.eirgridgroup.com/site-files/library/EirGrid/DSU-Application-Form.xlsx

[7] http://www.eirgridgroup.com/site-files/library/EirGrid/Statement_of_Intention_Transfer_Individual_Demand_Site_to_alternative_DSU.docx

removes the requirement to comply with the Substantial Financial Completion milestone for unit types delivering New Capacity with different delivery characteristics, subject to a number of requirements and is intended to result in more optimal use of existing demand side assets. This was recently approved by the Regulatory Authorities following a Consultation on the Modification Proposal.

As noted in Section 2.4, the RAs are currently considering the issue of available generation units which are subject to Difference Charges where they are not dispatched during an RO event, an area which is linked to a number of topics raised in responses to the Discussion Paper, including investment certainty for capacity providers and incentives to be available during times of tight capacity margins. The RAs understand from analysis of pricing events in September 2021 that this is an area that has impacted a number of DSUs and are considering this along with existing incentives for demand side flexibility.

4 Advance Notification prior to Amber Alerts

4.1 Advance Notification prior to Amber Alerts

When a System Alert is expected or in place, a notification is issued to market participants by the Market Operator, SEMO. The RAs sought feedback from stakeholders on any additional information that could be provided by the System Operators where there is a probability of tight margins. This could provide signals for generator availability and demand response where tight margins are expected.

Interested stakeholders were asked to provide feedback on additional information that could be published to signal periods of scarcity in advance of alert notifications being issued by the Market Operator.

4.2 Responses Received

An overview of respondents' views is provided below:

- EirGrid and SONI are open to further engagement on publication of additional information to signal scarcity but note that information is already published in this area and it has previously been agreed with industry that the publication of a market message along with a system alert is the most appropriate practicable approach to notify participants.
- In ESB GT's view, the provision of improved transparency, forecasting and predictability of data would allow market participants to better reflect scarcity in the Ex-Ante Markets and counter system tightness. This could involve the provision of consistent and accurate data to forecast amber alerts and signals to allow the ex-ante markets to reflect scarcity.
- Energia would welcome further information being provided on the extent and timing of anticipated reduced supply margins so that industry can assess if any additional actions can be taken to assist.
- EAI note in their response that EAI's members have previously requested advance notice of system issues by the TSOs as this provides useful signals to market participants which can allow units to be more responsive.
- PrePayPower would be in favour of providing more notice of system tightness events. They also suggest that the triad mechanism in GB should be considered which brings

about 2GW in reduction in peak demand on the tightest capacity days, which could deliver a 200MW peak reduction in the SEM.

- PPB agree that more notice prior to Amber Alerts may increase scope for assistance but this may help to assist DSU activity rather than conventional generators. Any information provided would need to be compliant with insider information obligations.
- In FERA and Powerhouse Generation’s view, advance notification of alerts would allow for advance communication for DSUs and the possibility to offset planned maintenance.
- SSE strongly support advance notice prior to Amber Alerts as a separate activity to the proposed adjustment to the ASP and SSE has previously requested greater advance notice via communications with SEMO.
- WEI and REI are of the view that system security concerns should be communicated as soon as possible rather than within day and that there should be more frequent and standard reporting of forward-looking capacity margins and system security concerns.
- Bord Gais Energy supports the prospect of providing more notice to market participants of when Amber Alerts may be expected to occur as advance notice would maximise any scope for a generator, supplier or DSU to react. BGE would welcome further consideration of the UK example on the Loss of Load Probability (LoLP) and De-Rated Margin (DRM) published a day in advance, along with publication of wind power forecasts and confidence intervals.

4.3 RA Considerations

Based on the comments received to this area of the Discussion Paper, a majority of respondents are in favor of improving the notice and information provided to market participants to signal potential tight capacity margins. The RAs are of the view that in this area, there are three general types of publications to consider.

Industry documentation such as the Balancing Market Principles Statement and TSO Operational Process documents describe for example the process of declaration of System Alerts and actions taken by the TSOs where there are tight capacity margins. Documents which have been reviewed by the RAs in this area are:

1. The Balancing Market Principles Statement
2. The Interim Cross Zonal TSO Arrangements for GB-ISEM go-live
3. TSO Winter Outlook
4. BP_SO_9.1 Demand Control Process

5. BP_SO_9.2 Declaration of System Alerts

Secondly, a range of operational data is published on a regular basis outlining the inputs to and outputs from the scheduling and dispatch process. The RAs have reviewed the range of publications available in this area[8] such as:

- The daily load forecast, representing the predicted electricity production required to meet demand, including system losses. This is updated on a continuous basis to account for actual demand conditions.
- Forecast output from wind units greater than 5MW including aggregate forecasts and uncertainty of the aggregate forecasts
- The Indicative Operations Schedule which provides a rolling schedule of unit commitment and dispatch actions
- Daily generator outage schedules and REMIT notifications, with publication of an all-Island Outage plan on a weekly and bi-monthly basis. REMIT notifications are issued in the event that there is a significant change to the outage schedule.

Thirdly, notifications are issued to the market where tight generation capacity margins are expected, where the TSOs may be required to take measures at high prices which impact on the Balancing Market and where a System Alert is being issued.

In terms of the accessibility of this information, as recently published in SEM-21-046[9] concerning SEMO's revenue allowance for the 2021-24 period, SEMO intends to carry out a website development project, focused on dynamic reporting and efficient access to data. In the RAs' view this is a critical project to improve access to information for participants and prioritization of delivery of this project is encouraged.

In terms of available industry documentation, the Balancing Market Principles Statement (BMPS) is reviewed on an annual basis to ensure that it is accurate and up to date. In the next revision, the RAs will consider the responses raised to this discussion paper and would encourage respondents to the next BMPS Consultation to highlight any inaccuracies or areas where further information or greater transparency on the operation of existing processes could be provided.

[8] https://www.sem-o.com/publications/tso-responsibilities/

[9] https://www.semcommittee.com/sites/semc/files/media-files/SEM-21-046%20SEMO%202021-24%20Price%20Control%20Consultation.pdf

The TSOs publish a Winter Outlook[10] on an annual basis which provides information on expected electricity demand and capacity margin on an all-island basis, covering the period from 1 November to 28 February each year. This provides a prediction of the MW capacity margin for this period and the drivers for this and is generally published in October. A number of respondents requested further information to be provided on capacity margins and the RAs note that information on this is not usually published outside of the Winter Outlook, for example on a rolling monthly basis. While the RAs recognise the range of detailed information already published by the TSOs and the resources required to compile reports, the RAs consider that it could be beneficial to provide monthly information on predicted capacity margins to the market throughout the year and will discuss this approach further with the TSOs.

In terms of notifications provided to the market in advance of System Alerts, the RAs understand that this is an area that would be difficult to provide a standard approach to as the conditions of each Alert will be different, however almost all respondents highlighted the benefit of earlier provision of information along with improved clarity in communications to explain the drivers of such events. The RAs request that the TSOs consider any improvements that could be made to the information provided in such notifications and whether early communication of this information can be prioritised further.

An explanation of the drivers for System Alerts or Cross-Zonal Actions carried out by the TSOs is usually provided ex-post through the Market Operator User Group (MOUG). This was an area considered by the Trading and Settlement Code Modifications Committee recently in relation to Mod_02_21, which related to how Cross-Zonal Actions are flagged. The discussions highlighted the view from market participants that more information could be provided in this area to explain the drivers for such actions and in the SEM Committee's decision it was noted that the RAs would engage with the TSOs to understand whether further information on Cross-Zonal Actions could be made available[11]. The RAs are of the view that there is merit in exploring the process for ex-post reporting of System Alerts in order to provide publicly accessible information on the conditions of each Alert and actions taken. At present, information is not provided in a standard format through the MOUG and while slides are made available after each meeting, these may not include the full level of detail presented by the TSOs including responses to stakeholder queries.

The Discussion Paper also referenced the publication of information on the Loss of Load Probability (LoLP) and De-Rated Margin (DRM) in the UK which is published a day in advance

[10] https://www.eirgridgroup.com/site-files/library/EirGrid/EirGrid-Group-Winter-Outlook-Brochure-2020-2021.pdf
[11] https://www.sem-o.com/documents/market-modifications/Mod_02_21/DecisionLetteronMod_02_21.pdf

by National Grid ESO to signal periods of tight margins. De-rated margin values are published on a Day Ahead, 8hr, 4hr, 2hr and 1hr profile to give advance notice of potentially tight Settlement Periods on the Transmission System[12]. This is an area of improved information provision that a number of respondents supported and the RAs request that this is considered in line with more regular reporting of predicted capacity margins.

5 Next Steps

The RAs welcome the responses received to the Call for Evidence and Discussion Paper on Scarcity Pricing and Demand Response in the SEM. As outlined above, the RAs do not intend to proceed to Consultation on changes to Administered Scarcity Pricing in the SEM at present, but are of the view that this is an area that should be reviewed further in the future in terms of the operation of scarcity pricing and broader market pricing, while taking into consideration changes that may also be required for compliance with the Electricity Balancing Guideline and the Electricity Regulation ((EU) 2019/943).

The RAs have commenced a programme of work to progress, as a priority, an enduring solution for DSU energy payments, and as discussed in Section 3.3, there are a number of additional specific areas identified which are being, or have been, progressed in relation to explicit demand response.

Areas of potential improvement have also been identified in relation to information provision on System Alerts and capacity margins and the RAs will engage with the TSOs based on the areas highlighted in Section 4.3 of this discussion paper and improvements that can be progressed.

[12] https://bmreports.com/bmrs/?q=transmission/lossloadProbDerateMargin