Call for Evidence Response Template

In order to respond to this Call for Evidence, please complete the tables below.

You only need to answer the questions that are most relevant and important to you.

Respondent details	
Company / Organisation	Demand Response Association of Ireland
Type of organisation / Sector	Aggregators of distributed generation and demand for wholesale market services
Address	17 Glandore Road
Respondent name	Lisa Foley
Job title	Head of Strategy and Regulatory Affairs @ GridBeyond
Phone number	0877209373
Email address	Lisa.foley@gridbeyond.com

Response to Call for Evidence		
Drivers of change		
Topic: Drivers of change	**Question number**: 1	**Question**: Which of the key drivers outlined present the largest impact for you or your organisation?

Response:

The DRAI represents approximately 600 MW of demand and embedded generation response across hundreds of industrial and commercial customer sites throughout the island of Ireland. By aggregating the electrical loads on these sites into substantial load portfolios, our members create predictable, reliable, and controllable assets, which provide a valuable source of Demand Side Flexibility (DSF). These load portfolios, commonly referred to as Demand Side Units (DSUs), actively participate in the Capacity, DS3, and energy wholesale markets and can be utilised by system operators to meet the near-time needs of the power system.

DRAI members are committed to shaping the future of power system flexibility through advancing DSF on the island of Ireland and continue to engage with new forms of distributed energy resources as they come online.

As aggregators, we acknowledge that wholesale electricity markets are inherently complex, and we realise that only the very largest energy consumers are in a position to allocate resources to successfully engage with any form of 'Time of Use' signal directly. We therefore argue that direct consumer response can really only be expected when the signal is either exceptionally acute (e.g. the £200/MWh DUoS tariffs prevalent during winter peak fifteen years ago) or simple (day-night DUoS rates).

Consequently, aggregation, whether passively through retail suppliers or actively through aggregators, is usually necessary to ensure that nuanced commercial signals are effectively communicated and managed for customers. In our view increased levels of digitisation and data usage are only expected to encourage response at lower voltage levels, as existing industrial and commercial customers have sufficient real-time controls and subsequent half-hourly revenue class metering to settle the delivered response.

Our members therefore argue that whilst the proposed drivers represent changes in scale (increased number of sites, with lower typical demand side flexibility capabilities), they do not represent a model change in business for the DRAI vis-à-vis its existing operations, as aggregation, digitisation and data usage is already operational for larger demand sites.

The DRAI would however also like to emphasise that there are several market barriers inhibiting that development of demand response and aggregation. In our view these specific challenges will need to be addressed in order to unlock the potential of flexible demand side resources and enable effective response to distribution tariff signals. These are addressed in question 2.

Topic: Drivers of change	**Question number**: 2	**Question**: In addition to the key drivers mentioned (distributed energy resources; increasing popularity of electric vehicles; development of battery technology; the emerging market for energy aggregators; and digitisation and data usage), are there any others that you consider to be a significant factor in affecting future electricity use?

Response:

The DRAI fully supports this review of the distribution tariff regime in Northern Ireland. We have noted above that aggregators act as an essential facilitator for DSF from most customers, and note two barriers to aggregation more generally, the latter of which we anticipate will restrict the level of demand response to the distribution tariff proposals. These barriers need to be addressed as a matter of urgency:

- No energy payments for demand response from Demand Side Units. This splits the overall wholesale market signals between the retail supplier of a customer's site driving passive response (who sees the benefit of avoided costs at the Imbalance Settlement Price), and the site's aggregator providing the explicit response (providing demand response usually for DS3 system services and the capacity market).
    - Further energy time-of-use tariffs avoided by suppliers will further complicate this scenario, which is one of the reasons why we advocate for time-of-use capacity (peak MW) distribution tariffs.
- Instruction sets limiting the potential response of generation to market signals. Generators are frequently prohibited from exporting from individual user's sites when part of a Demand Side Unit for certain times and periods of the year in Northern Ireland. These restrictions are known as Instruction Sets. It is the DRAI's position that these are a form of non-market based redispatch under Article 13 of EU/2019/943 (please see our response to SEM-21-026) and as such these should be monitored and minimised where possible.

We believe the distribution tariff review should be cognisant of these wider barriers. We draw attention to the fact that DSUs provide a valuable source of demand side flexibility in several markets (across energy, capacity, DS3, and now distribution tariffs / explicit regimes such as FLEX) and emphasise the need for congruency between the various signals provided by these markets. In our view it is only through the provision of coherent and predictable market signals that can be understood by all involved parties (customer, retail supplier, and aggregator) that an effective response can be reasonably expected.

Therefore without a corresponding review of the above barriers (no energy payments to DSUs and Instruction Sets), there is a risk that market actors will receive contradictory and confusing market signals which will compromise the effectiveness of the DUoS tariff review, and may ultimately result in failure to meet objectives.

Topic: Drivers of change	Question number: 3	Question: Do you consider that economy and efficiency should continue to be key factors in the Utility Regulators role in the transition process?

Response:

The DRAI recognise the role and legal duties of the Utility Regulator, and consider that as regulator for the energy industry it has the responsibility to determine the best balance of these factors to meet requirements.

We note that under the Withdrawal Agreement that the Utility Regulator is bound to Regulation EU/2019/943 (which has primacy over national legislation) and there are several provisions (see Article 18) on non-discrimination and cost-reflectivity in relation to the design of network tariffs. We understand that these requirements are included in the Regulation to ensure that tariffs relate solely to the specific policy objectives of recovering network costs.

We also draw attention to the fact that there is a legal requirement to duly take into consideration ACER's published opinion on distribution tariff setting as part of this review.

Topic: Drivers of change	Question number: 4	Question: Which of the key drivers outlined do you think present the largest impact for Northern Ireland specifically – and why?

Response:

No comment.

Topic: Drivers of change	Question number: 5	Question: How important and valuable do you consider energy aggregators to be?

Response:

In our response to SEM-20-042 and the SEMC decision SEM-20-088, we emphasised the important role for both suppliers and aggregators in assisting customers in responding to wholesale market signals. We also made an important distinction between these roles, in that aggregators assist customers in providing 'explicit (dynamic) demand response' whereas suppliers are more concerned with 'implicit (passive) demand response.

As previously mentioned, role of the aggregator becomes more important as the complexity of the market signal sent to customer to encourage response increases.

The DRAI recognise that costs on the distribution system are largely driven by peak customer usage where coincident with the system peak consumption. We therefore emphasise the importance of cost reflective DUoS tariffs, which should therefore move from an DUoS energy Time-of-Use signal to a capacity Time-of-Use signal.

Aggregators have a vital role in ensuring the balance of response between energy signals (increased consumption to support curtailment avoidance during periods of low price, reduced demand to avoid scheduling of CO2 intensive generation where possible), response when the system is short of generation, and finally unlocking the value of DER, batteries and EVs in relation to response to new DUoS tariffs (which will result in these new actors being able to connect and operate on the network in a capital-cost effective manner).

Topic: Drivers of change	Question number: 6	Question: In what ways could the electricity market in Northern Ireland be changed to make better use of energy aggregators?

Response:

In our response to Question 2 we identified the two important barriers that we anticipate will restrict the level of demand response to the distribution tariff proposals.

For a more detailed description of the issues faced by aggregators relating to these barriers please see our response to:

- *Discussion Paper and Call for Evidence on Scarcity Pricing and Demand Response (SEM-21-042)* for issues associated with the lack of energy payments for Demand Side Units, and demand response to pricing signals more generally, and;
- *Article 13 Clean Energy Package consultation (SEM-21-026) on the treatment of Instruction Sets*;

The 'Any other comments' section also includes relevant excerpts from these earlier responses.

Topic: Drivers of change	**Question number**: 7	**Question**: Do you think that digital technology, which offers customers live information on consumption and bills, is necessary for tariffs to provide adequate pricing signals?

Response:

We recognise that there may be value in proving ‘real-time’ information to customers in the case where there is an attempt to encourage a ‘explicit’ (passive) response from customers, or where customers are responding voluntarily to a demand reduction call. For example, the statistical data gathered via National Smart Meter Programme in Ireland provides evidence that customers with In-Home Display Units demonstrate an increased behavioural response to pricing signals.

We do however emphasise that the provision of ‘real-time’ information is not necessary where an aggregator acts on behalf of a customer or a group of customers, and retains instantaneous control of the customer’s responses.

Topic: Drivers of change	**Question number**: 8	**Question**: Is there existing technology in NI that could be used enable more efficient transition?

Response:

The DRAI consider that Demand Side Units have an important role in enabling the development of demand side flexibility, and therefore facilitating the growth or renewable energy generation and the overall the transition to a low carbon energy system.

We therefore emphasise the importance of policies and regulations to encourage the deployment of these demand side technologies, which are already fully operational (if not fully remunerated with energy payments) in Northern Ireland already.

Topic: Drivers of change	**Question number**: 9	**Question**: If changes were made to tariffs, should this wait until all customers have access to up-to-date technology that allows the change to have maximum impact?
Response: The DRAI recognise that the roll-out of any enabling technology needs to be communicated in advance (locations, customer types, timelines), to allow industry players to plan to respond to the roll-out programme. We would therefore be supportive of up front communications and engagement providing details of planned changes to tariffs. This would allow all customers and industry actors to become familiar with the proposed changes and highlight any unintended consequences and in our view would enable a smooth transition. Furthermore as the roll-out of the technology is expected to be a gradual transition we consider that there will be potential benefits in taking time to refine communications, in order to ensure any given class or location of customers are not left behind. We also believe that a gradual roll-out presents an opportunity for learnings to adjust tariffs as necessary if there are unintended responses or consequences.		
Tariff reform options		
Topic: Tariff reform options	**Question number**: 10	**Question**: Different tariff structures place emphasis on different factors such as cost-reflectivity, managing peak demand, simplicity, reducing price volatility, and providing more information to customers. Which objectives do you think tariffs should be designed to prioritise?
Response: The DRAI argue that in line with the requirements of EU/2019/943 – cost reflectivity (which captures managing peak demand, as peak demand drives costs) and where possible simplicity and predictability are the key factors to consider. In general, the DRAI contend that the current policy for generation charging for DUoS is appropriate, and any change to that structure for power exported to the Grid should be cognisant of cross-border competitive issues within the wider SEM.		
Topic: Tariff reform options	**Question number**: 11	**Question**: With regard to non-discrimination and cost reflectivity, are there deficiencies in the current tariff system which could be remediated?

Response: No comment.		
Topic: Tariff reform options	**Question number**: 12	**Question**: Do you think there are factors other than price that effectively incentivise consumers to change their behaviour? Which of these (including price) would you expect to be the most powerful incentive?
Response: Yes, the DRAI believe that increasing customer awareness for how changes in their behaviour will assist the transition to a low carbon energy system could be effective. We have previously discussed the multiple market signals that can be sent to consumers to influence how and when they consume power, and we consider signals linked to a positive environmental impact have the potential to have a definitive impact customer' behaviour. The DRAI supports the decarbonisation agenda through providing necessary system services to support increased renewable penetration, and have sites which increase consumption at times of high renewable penetration to reduce renewable curtailment. We emphasise that consuming power at times of high renewable penetration could be encouraged amongst residential customers via a focus on environmental concern and commercial customers through (Environmental, social and corporate governance), ESG requirements.		
Topic: Tariff reform options	**Question number**: 13	**Question**: Do you think that tariffs should be more tailored to individuals' energy usage, or be more a reflection of overall demand?
Response: Distribution costs are driven through two main factors: a) Peak demand requirements, to ensure peak flows on the network can be met; and b) Residual costs, which are largely independent thereafter on the operation of the network. The DRAI therefore support the transition of distribution tariffs away from MWh based charges to peak demand charges during periods which are typically coincident with peak demand flows, and towards a fixed demand based MW charge. We do however recognise that care is needed in the implementation of this general principle. For instance to avoid unintended impacts on vulnerable or fuel poor customers who are reliant on prepayment meters, these customers should continue on a MWh charging basis in order to protect them from high fixed charges or sudden loss of available credit due to the application of charges		

related to a few hours of high capacity usage.		
Topic: Tariff reform options	**Question number**: 14	**Question**: Because there are fixed costs to using the grid, costs are not exactly proportionate to consumption. Do you think that tariffs should be more reflective of the service that is being provided through the network connection?
Response: Yes. See our response to Question 13 above.		
Topic: Tariff reform options	**Question number**: 15	**Question**: To what extent do you think tariff structures should rely on new modern technology and data capabilities?
Response: The DRAI suggest: a) Tariffs should be designed with the intent of being cost reflective; b) Existing technologies provided by aggregators should be sufficient to support response from larger customers; c) Reliance on new technologies is necessary for passive response and settlement from smaller customers, who traditionally have not been HH metered up to now.		
Approaches to managing the transition		
Topic: Approaches to managing the transition	**Question number**: 16	**Question**: Would you expect tariff reforms to be introduced quickly over a short time period, or to be eased in gradually?

Response: We believe they can be phased in relatively quickly (with adequate advance notice) for larger customers on HH meters. Gradual phasing in will be particularly necessary if enabling technology is required for smaller businesses and residential customers. Communication of changes and the impact of changes will be important.		
Topic: Approaches to managing the transition	**Question number**: 17	**Question**: Would you expect tariff reforms to be applied to all consumers, or only certain subgroups or a certain proportion?
Response: If the proposed cost-benefit analysis for smart metering (which is likely to be a required enabling technology for small customers) is negative, then the review should presumably only apply to existing half-hourly metered customers. Otherwise, the DRAI see no issue with rolling out tariff reforms to all (noting care around tariff structures for prepayment meters, which may necessitate a different tariff structure).		
Topic: Approaches to managing the transition	**Question number**: 18	**Question**: Do you have views on whether new tariff structures should be opt-in, opt-out, or mandatory?
Response: This is a complex issue, which also interacts with data protection issues where the new tariff regime requires more granular data on electricity usage from individuals. There may be different answers for residential and commercial customers. It is therefore difficult to respond until the degree of change in the proposed tariff is known. We draw attention to the NSMP in Ireland which has dealt with these issues extensively, noting again that the apparent best solution is tariff dependent, and therefore a different approach for Northern Ireland may be appropriate.		

<table>
<tr><td>Topic: Approaches to managing the transition</td><td>Question number: 19</td><td>Question: In addition to (i) opt-in / opt-out, (ii) offering a choice from a range, or (iii) gradually phasing in a new system, are there other methods of offering new tariffs to customers that should be considered?</td></tr>
<tr><td colspan="3">Response:
No further comment.</td></tr>
<tr><td>Topic: Approaches to managing the transition</td><td>Question number: 20</td><td>Question: Do you think consumers would respond positively, if offered a range of options, or should one type of tariff be used for everyone?</td></tr>
<tr><td colspan="3">Response:
No further comment.</td></tr>
<tr><td>Topic: Approaches to managing the transition</td><td>Question number: 21</td><td>Question: Do you have views on whether consumers could modify their behaviour, if the incentive to do so was right? Or are usage patterns largely fixed by factors outside of their control?</td></tr>
<tr><td colspan="3">Response:
We note that customers do respond to price and information signals, based on past experience in Northern Ireland (high winter peak prices) and the NSMP study in Ireland.</td></tr>
<tr><td>Topic: Approaches to managing the transition</td><td>Question number: 22</td><td>Question: There are a range of options for monitoring the impact of reforms, such as surveys, analysis of complaints, billing questions, and usage monitoring analysis. Which do you think would be most effective?</td></tr>
<tr><td colspan="3">Response:
No comment.</td></tr>
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<tr><td>Topic: Approaches to managing the transition</td><td>Question number: 23</td><td>Question: Should consumers be protected from large bill increases caused by the reforms even if this needs to be funded by a cost elsewhere? If so, how long should the protections be in place for?</td></tr>
<tr><td colspan="3">Response:
No comment.</td></tr>
<tr><th colspan="3">Customer engagement and market understanding</th></tr>
<tr><td>Topic: Customer engagement</td><td>Question number: 24</td><td>Question: How engaged do you think consumers currently are on their energy usage and tariffs? For example, are they more, less, or adequately engaged relative to what would be expected?</td></tr>
<tr><td colspan="3">Response:
No comment.</td></tr>
<tr><td>Topic: Customer engagement</td><td>Question number: 25</td><td>Question: Would you identify particular demographics as having lower engagement? If so, why is this the case? Is it more due their own unwillingness to engage, or that the market is not very accessible?</td></tr>
<tr><td colspan="3">Response:
No comment.</td></tr>
<tr><td>Topic: Customer engagement</td><td>Question number: 26</td><td>Question: Do you have views on best method to engage customers more?</td></tr>
<tr><td colspan="3">Response:
No comment.</td></tr>
</table>

Topic: Customer engagement	**Question number**: 27	**Question**: Should unengaged customers be encouraged to increase their understanding of the market, or can they be trusted to opt-in?
Response: No comment.		
Topic: Customer engagement	**Question number**: 28	**Question**: At what stage in the reform process would it be optimal to engage consumers and (how) should this vary over time?
Response: The DRAI fully support engagement of consumer advocacy groups throughout the consultation process. We also suggest that focus groups / market research may be an appropriate means to gather representative views of the broader consumer population, ahead of a wider consumer engagement plan to support the roll-out of the new tariffs with firm realisable timeframes.		
Other challenges and risks		
Topic: Other challenges and risks	**Question number**: 29	**Question**: Are there any unique features of the Northern Ireland electricity distribution market that are particularly important to account for in the transition?
Response: We note that material changes to distribution line flows arising from the implementation of new distribution tariffs should reduce the need for Instruction Sets, and not exacerbate the scale or breadth of their usage.		
Topic: Other challenges and risks	**Question number**: 30	**Question**: There are a number of examples of tariff reform that have taken place in other countries. Are there specific examples that can be closely compared to the market in Northern Ireland? How important is it that the adopted reform approach is one that has been tried and tested elsewhere?

Response:

We note the ACER review of distribution tariffs, which notes the relatively slow progress of distribution tariff review within the context of EU Law.

"The review of national tariff frameworks shows that there were few recent significant changes in tariff methodologies, indicating that tariff stability of the distribution tariff framework has been so far a key objective pursued when setting distribution tariffs. There is a much wider number of ongoing possible changes (in more than half of the Member States)."

https://documents.acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/ACER Report on D-Tariff Methodologies.pdf

Any other comments

Please provide any other comments:

Excerpt from our response to SEM-21-042 – DRAI present the case for energy payments to Demand Side Units.

ENERGY PAYMENTS – MARKET DESIGN FAILURE

We consider it important to understand how the prevailing electricity market fails to provide DSUs with an incentive to be dispatched. This is vital context for any consideration of concerns around DSU availability.

In our analysis we compare the incentives provided to two 1 MW units which are identical, except that one is a DSU, and the other is a conventional, non-DSU unit. We find that, whereas the non-DSU unit is correctly incentivised to be available for dispatch and rewarded when dispatched, the otherwise identical DSU does not have a market incentive to maximise its availability, as such incentives are absorbed by the supplier contracted for energy at the site. We then explain how the introduction of energy payments for DSUs addresses this market failure, noting that this is an outstanding requirement under the current CRM State Aid approval granted by the EU Commission in Nov 2017.

Implementing an appropriate enduring solution to this market design failure is critical to ensure the proper participation of demand side participants on an equitable basis with other unit types in all aspects of the SEM. It is incredibly concerning that, since implementing a least-effort interim solution, the Regulators and SEMO have not engaged in any meaningful way with the DSR industry to ensure full State Aid Rules Compliance.

Background

The original Capacity Payment Mechanism in the SEM rewarded increased availability in Trading Periods of low margins through the varying Capacity Period Demand Price (CPDPh). The introduction of the I-SEM in 2018 replaced this with the Capacity Renumeration Mechanism (CRM). In the design of the CRM the SEM Committee issued a series of consultations, to which the DRAI responded by making a clear case for the introduction of energy payments for DSUs.

Although the final design of CRM did not include a mechanism to properly incentivise DSU availability (beyond the risk exposure faced due to potential Reliability Obligation difference charges in case a unit's availability is lower than its load-following capacity obligation), the DSU industry was reassured by the EU State Aid Approval[1], which mandated the implementation of an energy payment mechanism for DSUs.

Specifically, in addressing the particular exemption applicable only to DSUs in the ISEM rules, wherein they "are not subject to a payback obligation to the extent the demand reduction is delivered in line with the capacity contract" [para 126], the European Commission accepted that Irish Regulatory Authorities' position as an interim solution "in view of the potentially prohibitive effects that full application of the payback clause would have on DSUs and therewith on the participation of demand response as a whole in the CRM" [para130]. In reaching that conclusion "the Commission welcomes the commitment of the authorities to end the exemption for DSUs as of the delivery period starting October 2020" [para130].

Given the clarity provided by the EU Commission in the State Aid Approval notification, our members assumed energy payments for DSUs would be promptly implemented to enable non-discriminatory, equitable treatment for energy market participation.

In May 2019 the SEM Committee issued a consultation on CRM DSU Compliance with State Aid (SEM-19-013). In the DRAI response we clearly stated our concerns, "that tenets of the proposed enduring solution do not address the challenges associated with achieving compliance with the State aid decision in a manner that also delivers the required support of increased demand-side participation. In fact the DRAI consider that the proposed enduring solution represents a counter-incentive, and that its introduction would result in an erosion of the DSU industry in Ireland".

We also "emphasised the need for the RAs to initiate engagement with our industry as we believe that proactive discussions would facilitate sharing of views and enable the development of solutions designed to fully integrate DSUs into electricity markets without setting them at a disadvantage to other market participants".

In July 2019 the SEM Committee issued their decision paper CRM DSU Compliance with State Aid (SEM-19-029). "The SEM Committee decided that energy payments, in respect of DSU volumes dispatched in the balancing market over and above their ex-ante position, will be made to DSUs at those times when the Imbalance Price (PIMBγ) is above the Strike Price, i.e. when DSUs are liable to pay difference charges" [para 2.4.2]. And also decided "that this Interim Solution for DSUs will apply from the start of Capacity Year 2020/21, i.e. from October 2020 in line with the State aid approval for the CRM".

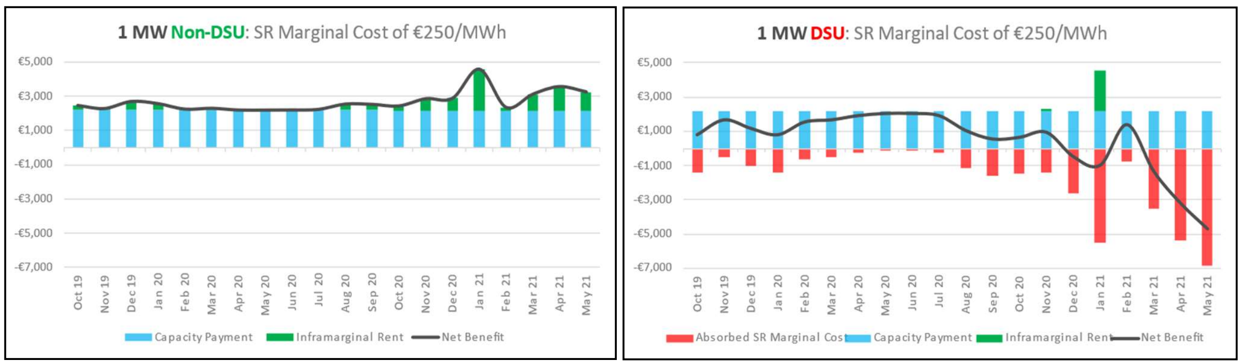
[1] EU Commission, C(2017) 7789 final, No. SA.44464 / SA.44465 (2017/N) – Ireland/ N Ireland Capacity Mechanism, 24th November 2017.

Our members question whether this current least-effort interim solution satisfies the EU State Aid Approval requirements, as it perpetuates a broken market design. In addition, it certainly seems inconsistent with the requirements for non-discriminatory treatment between different classes of market participant in Article 6 and Article 17 of the Internal Market for Electricity Regulation EU/2019/943 and Directive EU/2019/944 respectively. For these reasons, the DRAI have repeatedly emphasised the need to implement an enduring solution, and have identified the introduction of an energy payment mechanism for DSUs as a key priority for the industry.

Comparison of the incentives faced by a non-DSU versus a DSU

The following example compares the net benefit for a 1 MW non-DSU unit with an otherwise identical 1 MW DSU. It assumes that both units will be dispatched by the market whenever the imbalance price is greater than their short-run marginal cost of €250/MWh. Capacity payments are calculated on the assumption that the units are derated in-line with a 2 hour maximum run time. For simplicity, the dispatch model in both instances is not constrained as it is not material to the principle being illustrated.

Comparison of a Non-DSU unit (left) vs. a DSU (right), both with a short-run marginal cost of €250/MWh



The Figures above show monthly total revenues October 2019 to May 2021 based on real Imbalance Settlement Price Data. Reliability Option Difference Charges occurred in November 2020 and January 2021. The Figure for the DSU on the right assumes a retail price of €80/MWh (ex

VAT) that is avoided when the generator is dispatched on. The DSU Figure excludes the trading impact on the retail supplier, to which neither the DSU nor the IDS have access.

For the non-DSU unit, each energy market dispatch provides revenues which cover the unit's short-run marginal costs (SRMC), and the unit benefits from inframarginal rent in most instances. **Dispatches are desirable** and the unit is incentivised to make itself available for dispatch, and to offer below the strike price.

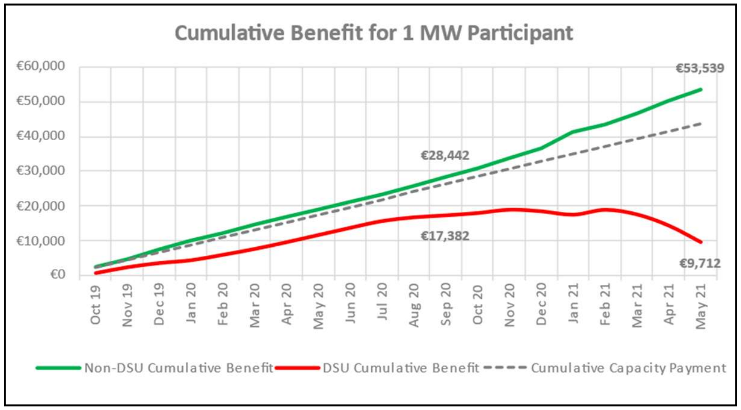
For the DSU, each dispatch will result in participating sites having to absorb their SRMC unless the imbalance price exceeds the strike price. Every time they are dispatched like this, they make a loss relative to their saving on their retail tariff. **Dispatches are regrettable,** so there is no energy market incentive for the unit (customer sites) to make themselves available for dispatch.

In both cases, the units receive capacity market revenues, but whereas the non-DSU unit also receives the benefit of inframarginal rent when they are dispatched, the DSU only receives this on the rare occasions that the imbalance price exceeds the strike price: all other dispatches erode away the benefit of participation; if there are too many, the customer will regret joining the market at all, and is likely to leave.

Note that these differences have nothing to do with the capabilities and cost structures of the units – it's just down to the discriminatory treatment in settlement.

Comparison of the cumulative benefit for a non-DSU versus a DSU

The chart below simulates the cumulative commercial impact of the current market design on the two 1 MW units evaluated above (a 1 MW non-DSU versus a 1 MW DSU, each with a SRMC of €250/MWh) over an 18 month period. For the non-DSU, where the market dispatch provides revenues which at least cover its SRMC of €250/MWh whenever dispatched, the market signal clearly provides a strong financial incentive. Conversely, for the DSU unit, where each dispatch requires the unit to absorb its SRMC in exchange for avoidance of its retail tariff costs unless the imbalance price exceeds the strike price, the financial incentive to be available for dispatch is absent. It clear there is a substantial differential in the benefit of being dispatched to a non-DSU and a DSU.



Load following

The example provided clearly illustrates a flaw in the current market design, in that IDSs are disincentivised from making volumes available in excess of the load following adjusted awarded volume due to the increased exposure to costs that must be absorbed when dispatched.

The DRAI therefore contend that under the current market conditions it is entirely rational for IDSs to only make available their load following Reliability Obligation, as this is consistent with the market signals provided by the Capacity Renumeration Mechanism (CRM).

If the intention is to increase availability from DSUs, we argue that it is the market that needs to create the appropriate signal for IDSs to respond to. Without such a signal, aggregators simply have no way of incentivising their customer IDSs to further increase their viable volumes, and therefore cannot be accused of holding back availability.

Missing signal to incentivise DSU availability

The difference in benefit received by the two unit types evaluated is due to the fact that the costs for the non-DSU unit are always at least met for each energy market dispatch, and the unit benefits from inframarginal rent in most instances. In contrast, under the current interim approach to energy payments, the DSU only receives energy revenues if the imbalance price exceeds the strike price. While this does indeed mean that if a DSU is dispatched during a capacity market event, it will receive revenues to cover its reliability option difference payment, this interim approach leaves serious distortions which undermine the incentives for DSUs to be available.

These make the incentives faced by a DSU very different to those faced by a generator. Specifically:

- Since the DSU will incur dispatch costs – through customers' opportunity costs – but receive no revenues enabling it to recover these costs when the reference price is less than the strike price, this means that there is a strong incentive not to offer resources at low prices, as this would increase the risk of dispatch.
- While many demand-side resources have high SRMC, there are others that have SRMC substantially below the strike price. Since there is no opportunity for such resources to be dispatched profitably other than during capacity market events, there is no incentive for aggregators to seek out and cultivate them.
- Hence, rather than having a spread of offer prices from DSUs with different characteristics, which would help make the market clear more efficiently, it all tends to be offered at high prices.
- Since dispatches are essentially opportunities to lose money, it is difficult for aggregators to encourage customers to maximise their availability for dispatch.
- There are essentially no "carrots" to reward increased availability – just the "stick" of uncovered difference payments if a unit's response during a capacity market event is less than its de-rated load-following capacity obligation.

All of these issues would be resolved by making the energy payments to DSUs when they are dispatched, just as payments are made to all other resources.

EU Legislative requirements

The DRAI emphasise that the non-payment for balancing energy delivery from DSUs is a clear discriminatory exclusion from an entire market, which remains an outstanding requirement for State Aid Compliance for the CRM. We draw specific attention to the SEM Committee Decision on DSU State Aid Compliance (SEM-19-029), which *noted that an optimal solution would be to fully integrate DSUs into the market and calculate actual demand response in order to provide for energy payments for DSUs in the Balancing Market.*

Our members continue to emphasise that the absence of an energy payments mechanism for DSUs and the continued uncertainty regarding its implementation is a key barrier inhibiting the development of this valuable, indigenous source of demand side flexibility. We strongly argue that the introduction of full energy payments for DSUs is needed to provide the enduring long term mechanism required to improve DSU availably. In our view this is the clear solution to unlock the potential of the technology and to provide the much needed capacity to address security of supply issues.

The DRAI urge the SEM Committee to take action as a matter of urgency, to instigate the design and implementation of an energy payment mechanism for DSUs. This mechanism is the enduring solution to the current market failure as it provides IDSs with an incentive to be dispatched, and will continue to be an ongoing requirement in the market.

Excerpt from our response to SEM-21-026 – DRAI present the case for removal of instruction sets.

As you are aware, Instruction Sets are applied by the DSO / DNO to the ability of aggregators to use Individual Demand Sites (IDS) flexibility where it is assessed such flexibility as part of an aggregated unit (AGU / DSU) could cause an unacceptable condition on the distribution network. These Instruction Sets apply varying degrees of static restriction on the periods during which an IDS is able to participate within a DSU / AGU.

It is important to note that Instruction Sets are not reflected within the connection agreement of the user. They are a scheduling restriction on the activities of an aggregator.

The DRAI are of the view that Instruction Sets are a form of non-market based redispatch, which places new obligations on DSOs on the operation, reporting, mitigation, and (dependent on the connection offer) compensation of same.

Analysis of Instruction Sets under the Regulation

The specific text from the consultation is as follows:

"On the issue raised concerning instruction sets applying to Demand Side Units, DSUs' PNs, forecast availability and declared availability prior to Balancing Market gate closure and in real-time operation reflect these DSO/DNO Instruction Sets. This affects the dispatch quantity for a DSU in order to manage congestion at a distribution level and the RAs are of the view that where any changes are introduced at a distribution level to provide market-based solutions for congestion management, this issue will need to be considered further. The Balancing Market Principles Statement notes that where constraints arise on distribution network connected units which impact on the TSOs' ability to dispatch or control such units, the constraint is reflected in the scheduling and dispatch process. Where a distribution connected generator, participating in the SEM, is subject to a TSO constraint the RAs' understanding is that there is no distinction between the treatment of such units in terms of bid offer acceptance or balancing market settlement.

As more generation connects at the distribution level, the management of constraints which limit access to the energy market will need to be addressed. Feedback is invited from Demand Side Units and System Operators on this point in particular as part of this Consultation Paper and how it may best be managed in terms of Article 13 of the Regulation."

In the DRAI's view, instruction sets are a measure, activated by the DSO/DNO, which curtails a demand site's load pattern (vs. that which it would have been in the absence of the instruction set) in order to change the physical flows on the power system to relieve physical congestion. Therefore, instruction sets are clearly a form of redispatch as per the definition in the Regulation 2019/943.

Instruction sets are also not market-based. The SEM Committee's own text recognises this fact. Indeed, instruction sets clearly meet the test of Article 13 (3) (c) to be classified as non-market based, as there is no functioning market to allow for local distributed connected resources (demand and generation) to compete to resolve the distribution network congestion issues which require their imposition.

We note the SEM Committee's proposal within the consultation:

"The Regulatory Authorities acknowledge that future market developments may include new forms of dispatch and redispatch at the distribution level."

It is the DRAI's view that these redispatch actions are being taken today implicitly through changing the availability of aggregators of IDSs (where the IDSs have signed up to no such restriction of their behaviour under their own connection agreements).

Instruction Sets: Examples

It is the DRAI's position that Instruction Sets are a form of non-market based redispatch in scenarios where Demand Side Units (DSUs), due to an instruction set, are prohibited from delivering an ex-ante market position, or prevented from being dispatched in the Balancing Market as they would otherwise have been. Taking the following example:

- A capacity reliability option event occurs in the Balancing Market (the ex-ante market clearing prices for the same period were below the reliability option strike price).
- A DSU with a Short Run Marginal Cost greater than the ex-ante clearing prices but less than the reliability option strike price would not have an ex-ante traded position but would be called on in the Balancing Market to deliver below the reliability option price.
- However, where the DSU contains an Individual Demand Site (IDS) that is subject to an instruction set, defined and implemented by the DSO, which prevents it from providing coordinated demand response, that would result in the DSU being redispatched away from its desired running level.
- This would result in the DSU having an exposure to uncovered reliability obligation Difference Charges, and potential penalties under the DS3 System Services even if the IDS subject to the instruction set was fully available to respond.
- The current market design results in a material risk exposure for Demand Side Participants as a result of instruction sets which are wholly outside of the control of the DSU or the IDS.

The fact that in the case of instruction sets this redispatch arises through an obligation for a unit to declare its availability in a manner that reflects the instruction set is besides the point: that is an implementation approach which allows the DSO to communicate the presence of its redispatch to the TSO through forced market participant declarations.

Consequences of Instruction Sets being a Form of Redispatch

As Instruction Sets are a form of redispatch, this places an obligation on the TSOs / DSOs to report on the level of instruction sets and the level of non-market based redispatch arising (Article 13(4)(b)), and where aggregators contain sites with HE CHP and Renewable Energy, and to take measures (Article 13(5)(b)) and report on those measures (Article 13(4)(c)) to reduce the level of redispatch.

A hierarchy of how Instruction Sets are applied to renewable, HE CHP and self-generated electricity from those sources when not exported to the grid is required under Article 13(6).

The DRAI supports these obligations. Instruction sets appear to be often crude and wide-scoping in nature. For example, they require non-delivery of response on a seasonable basis to static MW limits. This is far below the standards envisaged in Regulation 2019/943 and the requirement that non-market-based re-dispatch should only be used insofar as no market-based alternative is available or all available market-based resources have been used.

Compensation for Non-Market Based of Downwards Redispatch

Article 13(7) sets out the requirements for compensation for generators which are subject to redispatch:

"Where non-market based redispatching is used, it shall be subject to financial compensation by the system operator requesting the redispatching to the operator of the redispatched generation, energy storage or demand response facility except in the case of producers that have accepted a connection agreement under which there is no guarantee of firm delivery of energy."

We note that the IDS have not accepted a connection agreement under which there is no guarantee of firm delivery of energy. Therefore, compensation must apply.

Article 13(7) continues:

"Such financial compensation shall be at least equal to the higher of the following elements or a combination of both if applying only the higher would lead to an unjustifiably low or an unjustifiably high compensation:

(a) additional operating cost caused by the redispatching, such as additional fuel costs in the case of upward redispatching, or backup heat provision in the case of downward redispatching of power-generating facilities using high-efficiency cogeneration;

(b) *net revenues from the sale of electricity on the day-ahead market that the power-generating, energy storage or demand response facility would have generated without the redispatching request; where financial support is granted to power-generating, energy storage or demand response facilities based on the electricity volume generated or consumed, financial support that would have been received without the redispatching request shall be deemed to be part of the net revenues."*

DSUs' financial support flows through the Capacity Mechanism, being the net revenues from Capacity Payments and Difference Payments. The intent of the Regulation compensation is clear: demand response facilities should be made financially whole to the level of revenues they would have received were it not for the non-market based redispatch.

This compensation must be coordinated with Reliability Option payments within the capacity mechanism to ensure that a unit with sufficient availability does not fall short of meeting its delivery obligations solely due to the impact of an instruction set. For example, a market unit which is restricted from delivering energy in the Balancing Market to meet its Reliability Obligation and which was otherwise available at a level in excess of its adjusted load-following obligation should be compensated for any Reliability Obligation Difference Charges associated with under-delivery directly attributable to an instruction set.

Conclusion:

When instruction sets on IDSs within DSUs were first introduced in 2015 it was clearly stated by the CRU (the Commission for Energy Regulation at the time) that such instruction sets should restrict dispatch only so far as required to mitigate risks to system security and should set out as specifically as possible the conditions under which they are required (vs. 'all year, all the time' restrictions). The guiding principle that instruction sets should become more granular (less restrictive) over time was also clearly enshrined.

It is important that Instruction Sets should be as dynamic as possible (reflecting actual system conditions and only applying restriction when, and as much as required to protect the network) and the DSO/DNO should be incentivised to remove / reduce their use as much as possible. The DRAI believes that correctly classifying instruction sets as non-market redispatch, with the associated reporting and compensation requirements, will clearly allocate the associated financial risk with the DSO/DNO which is responsible for alleviating the network constraints / conditions that require their imposition (vs. this financial risk sitting with the AGU/DSU as is currently the case).

How to respond

Representations may be made on or before 5pm on 16 August 2021. Responses can be sent in writing to or by emailing:

Alan Craig

The Utility Regulator

Queens House

14 Queen Street Belfast

BT1 6ED

e-mail: alan.craig@uregni.gov.uk

and

e-mail: Electricity_Networks_Responses@uregni.gov.uk

Our preference is for responses to be submitted by e-mail.

Confidentiality

Please note that we intend to publish all responses unless marked confidential. While respondents may wish to identify some aspects of their responses as confidential, we request that non-confidential versions are also provided, or that the confidential information is provided in a separate annex.

As a public body and non-ministerial government department, the Utility Regulator is required to comply with the Freedom of Information Act ("FOIA"). The effect of FOIA may be that certain recorded information contained in consultation responses is required to be put into the public domain. Hence it is now possible that all responses made to consultations will be discoverable under FOIA, even if respondents ask us to treat responses as confidential. It is therefore important that respondents take account of this. In particular, if asking the Utility Regulator to treat responses as confidential, respondents should specify why they consider the information in question should be treated as such.

The Utility Regulator has published a privacy notice for consumers and stakeholders which sets out the approach to data retention in respect of consultations. This can be found at https://www.uregni.gov.uk/privacy-notice or, alternatively, a copy can be obtained by calling 028 9031 1575 or by email at info@uregni.gov.uk.

This paper is available in alternative formats such as audio, Braille etc. If an alternative format is required, please contact the office of the Utility Regulator to request.