ISEA
Irish Solar Energy Association

IRISH SOLAR ENERGY ASSOCIATION

Response to Consultation SEM-20-028 on the Implementation of Article 12 and 13 of EU Regulation EU/2019/943 ("the Regulation")

June 2020

The Irish Solar Energy Association (ISEA) welcomes the opportunity to respond to the SEM Committee's consultation on the implementation of Articles 12 and 13 of EU Regulation EU/2019/943.

Introduction

The Irish Solar Energy Association (ISEA) was founded in May 2013 and is the solar industry representative body for the island of Ireland. With over 50 members, ISEA is committed to highlighting the potential for solar energy's contribution to Ireland's economic and environmental future. ISEA is committed to contributing to the development of viable renewable energy policies that support the development of solar in Ireland via research, consultation, conferences and other fora that bring key stakeholders together to shape policy. ISEA is keenly aware that in order to build a long-term sustainable industry in Ireland, a stable regulatory framework is required. To achieve this, the industry must deliver value for money to the exchequer and consumer and gain popular support. With solar projects comprising c25% of the qualifying capacity for the RESS-1 auction it is important the issued raised are suitably addressed.[1]

Timing and Process

ISEA's primary concern with this consultation is its timing in relation to the first Renewable Energy Support Scheme (RESS-1) auction. ISEA wishes to have sufficient certainty for its members when formulating their auction offers. The RESS-1 auction offers are scheduled to be finalised by Tuesday 28th July 2020, the "Auction Submission Closing Date".

It is unlikely, however, that all detailed aspects of the matters consulted on will be decided (must less implemented) by this date. The consultation itself is complex. Full implementation of the treatment of new renewables without Priority Dispatch could potentially take years. Given the delays, however, experienced by the solar industry in Ireland getting to an operational subsidy scheme, there is no appetite within ISEA to delay the RESS process for that complete certainty to emerge.

[1] https://www.cru.ie/wp-content/uploads/2020/04/CRU20051a-Letter-to-Minister-Bruton-regarding-CRU-RESS-initial-competition-assessment.pdf

Ultimately, a completed design will lead to financially-modellable future outcomes for the downward redispatch and compensation for future solar PV projects. This will lead to efficient RESS offer prices, delivering value to the consumer. Without this full certainty, as unfortunately will be the case for the first RESS auction, auction participants will have to individually judge the risks and price these risks into their offers. RESS, unlike the previous ROC and REFIT regimes, allows renewable generators to adjust their prices as required. Therefore, this uncertainty comes at a real cost to consumers (whereas previously this uncertainty was absorbed within the fixed subsidy price).

It is important therefore to take fast action to reduce uncertainty insofar as possible given the time constraints.

ISEA therefore strongly urges the SEM Committee to take the following actions:

1) **Deliver Decisions Urgently on the Central Aspects of the Consultation prior to the Auction Submission Closing Date.**

These aspects are:

- what generators commissioned post 4th July 2019 will qualify for Priority Dispatch on the basis of a "concluded contract", and
- what "significant modifications" to a power generating facility result in the loss of Priority Dispatch.

ISEA recognises that this requires the SEM Committee to reach this decision within a number of weeks post closure of the consultation. We do not believe, however, this request is unduly onerous, particularly within the context of the Regulation having been published for almost a year, and the Regulation having come into effect on the 1st January 2020. Extra-ordinary meetings of the SEM Committee should occur to meet this decision timetable if required.

2) **Deliver a Consultation Plan to Resolve Outstanding Issues**

It is likely some aspects of the consultation will not proceed to decision. The Regulatory Authorities themselves have acknowledged that further clarifications are required from the System Operators in the text of their consultation. Indeed, it may be impossible for the System Operators to give clarity on certain aspects in their response, e.g. the technical elements of notification and dispatch, without some narrowing of the potential policy-level decisions by the SEM Committee. Further consultation will be necessary. It is therefore equally important (but somewhat less urgent) to publish a consultation plan to deliver full certainty on:

- the treatment of non-Priority Dispatch renewables when redispatched and how that redispatch is shared (if at all) with Priority Dispatch renewables; and
- the rules for compensation for downward redispatch for all renewables.

For the avoidance of doubt, ISEA supports full compensation for downward redispatch of renewables, including compensation for downward redispatch of non-firm curtailment. This is in line with the Irish Wind Energy Association (IWEA) position in relation to such matters.

This plan should be cognisant of potential timelines for the RESS-2 auctions, and the SEM Committee should liaise with both Departments to ensure that the timelines for certainty do not have greater than necessary negative impact on the delivery of Ireland or Northern Ireland renewable policy.

Central Aspects of the Consultation: Qualification for, and Loss of Priority Dispatch

Question 2 (relating to what projects have Priority Dispatch) and Question 11 (relating to the circumstances were Priority Dispatch may be lost) are the key questions at this time for any RESS auction participant and are addressed together below under point 2). First, under point 1), ISEA wishes to give some insight as to the level of regulatory risk faced by Priority Dispatch and non-Priority Dispatch renewables in the RESS auction.

Note while that this response contains indicative views as to certain risk factors which a RESS participant may consider when formulating their RESS offer price, these are illustrative only, are not purported to be complete, are not necessarily appropriate for any given auction participant, and are not intended in any way to provide guidance to our members. They are provided to give supporting rationale to the SEM Committee as to why RESS-1 auction participants should benefit from full Priority Dispatch.

1) Consultation Review with a View on RESS Auction Offers

There is a secondary tier of issues (some not addressed in the consultation) which are important.

- The paper does not address below de minimis generation. It is ISEA's contention that below de minimis generation, even if not a market participant, should be entitled to the same level of compensation for redispatch as market participants. If this were not the case, then either:
    - Below de minimis projects need to become market participants at potentially much greater fixed costs and overheads, leading to a more expensive RESS auction offer in terms of economies of scale; or
    - Below de minimis projects without such compensation are placed at a material disadvantage relative to larger projects in the RESS auction.
- While it is outside the scope of the SEM Committee's vires, the RESS terms and conditions pass through compensation for constraint but are silent on the treatment of any compensation for curtailment. If this is not confirmed at a high level in advance of RESS offer submission, then either:
    - RESS participants will offer (and lock-in if successful) higher than necessary RESS support prices for a period of 15 years; or
    - RESS participants will take account of assumed compensation, lowering their offer and potentially clearing at a price which is not sustainable for the duration of the investment.
- Again, while it is outside the scope of the SEM Committee's vires, the ECP-2 decision from the CRU (CRU/20/060) has set out a programme to provide a schedule for firm access (under a currently to-be-decided methodology) for post Gate 3 connection offers and agreements (which make up the bulk of RESS-1 participants).

These secondary tier issues effectively mean RESS-1 participants (irrespective of whether they have Priority Dispatch or not):

- Don't know if they are eligible for any compensation for downward redispatch if de minimis; and
- Don't know whether the RESS terms and conditions will pass through compensation for downward redispatch which is identified as curtailment.

If firm access is a requirement for downward redispatch compensation for constraint and/or curtailment, the timeframe of when that firm access will be available is unknown.

In February 2020, Northern Ireland solar PV with Priority Dispatch experienced downward redispatch (and possibly an element of downward energy balancing dispatch) of the order of 9% of available energy[2]. Depending on projections of the level of build out and exposing new renewables to energy balancing in advance of Priority Dispatch plant, credible scenarios can be developed where non-Priority Dispatch solar PV may be dispatched down far in excess of this figure.

This creates large double-digit percentage swings in RESS offer price for participants for non-Priority Dispatch renewables. Even with Priority Dispatch there is uncertainty and inefficiency in building up a RESS auction offer price due to the uncertainty around downward redispatch compensation. Without Priority Dispatch, however, the spread of potential impacts on revenues is even worse.

That is before one even begins to assess the potential costs of any new system operation regime for a renewable generator outside of the existing Priority Dispatch methodologies. If the EDIL system is to be used to control non-Priority Dispatch generators, will this require manual staffing of a control facility 24-7 as is required under Grid Code? If the control systems will be materially different to the existing non-synchronous dispatch tool, how much do they cost, can OEM's integrate to these new systems or will they have to develop new technologies, and will it delay delivery of projects reducing the duration of (or even potentially losing entirely) RESS support as a consequence? Will trading inefficiencies or notification declaration inaccuracies reduce the potential delivery of power from a non-Priority Dispatch solar PV plant?

In short, while there are issues and uncertainties with Priority Dispatch (including the unclear mechanism by which Priority Dispatch generators avoid production at times of negative prices), it is clear that greater RESS certainty arises from having Priority Dispatch than not having it.

This momentary uncertainty will be fixed into fifteen-year RESS contract prices,

[2]http://www.eirgridgroup.com/site-files/library/EirGrid/2020-Qtrly-Solar-Dispatch-Down-Report.pdf

which will have to be paid by consumers. Not only is it important, therefore, to make a decision quickly in relation to Question 2 (who qualifies for Priority Dispatch) and Question 11 (how one might lose Priority Dispatch), but that the decision results in narrowing down that risk as quickly as possible.

2) Priority Dispatch, Question 2 and Question 11

ISEA supports the SEM Committee's proposal in Question 2 that generators eligible for a Connection Offer by 4th July 2020 should be eligible for Priority Dispatch, i.e. all RESS-1 participants will have Priority Dispatch.

ISEA does sound a note of caution, however, as this needs careful legal review. The test in the Regulation is that no generator commissioned post July 4th, 2019 shall qualify for Priority Dispatch, "subject to contracts concluded". It is not immediately clear that whether the future offer of a connection agreement can meet this contract concluded test.

If it does not, then it may be necessary to have non-Priority Dispatch and Priority Dispatch generators (those with connection agreements signed before the July 4th cut-off date) participating in the same RESS-1 auction. ISEA estimates that 92 solar projects participating in RESS-1 executed connection agreements prior to the cut-off date and would therefore qualify for Priority Dispatch[3]. It is noted that RESS auctions are to be held regularly and periodically, meaning unsuccessful RESS-1 auction applicants disadvantaged through not having Priority Dispatch are unlikely to lose their projects – they will have opportunity in the next RESS auction.

A connection agreement is one of the few contracts that are objectively dated and are demonstrably a contract so are a suitable test. Furthermore, if an entity had signed a connection agreement prior to 4th July 2019, they could reasonably feel aggrieved that they had to forego Priority Dispatch, particularly if they failed to clear the RESS auction due to taking a prudent (or more conservative view) of the non-Priority Dispatch risks in the formulation of their auction offer.

Finally Question 11 deals with the issues of loss of Priority Dispatch. ISEA believes

[3] http://www.eirgridgroup.com/site.files/library/EirGrid/TSO_NonWind_Contracted_29.05.2020.pdf & https://www.esbnetworks.ie/docs/default-source/publications/dso-contracted-non-wind-generators-q1-2020.pdf?sfvrsn=789506f0_12

that the SEM Committee has not appropriately considered the Regulation in this regard, stating that any issue of a new Connection Agreement or an increase in Maximum Export Capacity of a Connection Agreement would result in loss of Priority Dispatch.

Article 12 (6) states that Priority Dispatch no longer applies "from the date on which the power-generating facility becomes subject to significant modifications". If a new connection agreement is required as a result of such change, then Priority Dispatch is lost. There are many procedural reasons why new connection agreements are issued where there is no material change to the power-generating facility. A procedural reissuing of a connection agreement does not meet the test of Article 12 (6), because:

- the new connection agreement was not required – it could just as readily have been a modified connection agreement; and critically
- there was no material change to the power generating facility.

Furthermore, connection agreements are frequently merged (and may have been merged post July 4th, 2019) to facilitate a power-generating facility that itself had not materially changed. Such mergers may have resulted in a new connection agreement. Again, the reallocation of grid capacity is not the test required in the Regulation; the test is whether there was any material change to the power generating facility that required the issue of a new connection agreement.

In summary, it is ISEA's position if the AC installed capacity of a generator has not increased, if the generator has not been repowered, or if the generator has not been replaced with a different technology, then business-as-usual configuration of connection offers and agreements should not trigger loss of Priority Dispatch as there has been no material change to power generating facility.

3) Remaining Questions

Outside of our response to Question 2, ISEA supports IWEA's position in relation to the remainder of the consultation, including in particular that "unjustifiably high compensation" for downward redispatch should be tested at the individual generator level and not the system-level. The amount of compensation is therefore justified at the generator level, and therefore should be paid to all renewable generators.

We have, however, provided further incremental response to the questions posed in the Appendix below.

Appendix 1 – Response to Consultation Questions

Consultation Question 1: Do you agree with the RAs' interpretation of the requirements under Articles 12 and 13 and specifically the application of dispatch, redispatch and market based/non-market based redispatch in the SEM?

ISEA agrees that:

- Dispatch in the Regulation maps to the concept of energy balancing in the SEM;
- Redispatch in the Regulation maps to the concept of non-energy actions in the SEM.

Detail, however, is important.

For example, downward redispatched renewables in the SEM to meet a SNSP limit will be defined as curtailment through both the SEM-13-010 definition and the nature of the control instruction from the TSO. In market pricing, however, if the total amount of available renewable energy exceeded demand in that particular 5-minute period, some of those downward redispatch actions may be classified as energy balancing. Subsequently in settlement, however, the "curtailment" flag will be still be attached to the downward dispatch, and all such generators will be settled under the existing curtailment rules.

Furthermore, the TSO in dispatch may be of the view that they are taking energy-balancing actions when the traded market is in fact entirely balanced, for example if the day-ahead market cleared the correct amount of energy but the TSO has priority dispatch renewables with availability and/or conventional generators providing nominations greater than their traded position.

Clear definitions are therefore required as to what is meant by energy balancing.

Consultation Question 2: In terms of the practical implementation of Article 12(1) to introduce a distinction between units which retain eligibility for priority dispatch and those which are not eligible, the RAs propose;

- **Where a commissioning programme has been agreed with the TSOs on or before 4 July 2019, it is proposed that such units will be eligible for priority dispatch.**
- **Where a unit is eligible to be processed to receive a valid connection offer by 4 July 2019, the RAs are of the view that this represents a**

contract concluded before priority dispatch ceases to apply under Article 12 and that such units are also eligible for priority dispatch.**

- **Where a unit becomes active under a contract concluded before 4 July 2019 including a REFIT letter of offer or PPA, the RAs welcome feedback on the proposal for such generators to be eligible for priority dispatch.**

Interested stakeholder's views are invited on these proposals.

Please refer to the main body of our letter.

Consultation Question 3: It is the RAs' understanding that any unit which is non-renewable dispatchable but is no longer eligible for priority dispatch can be treated like any other unit within the current scheduling and dispatch process, through submission of PNs with an associated incremental and decremental curve. Feedback is requested on this aspect of implementation of Article 12 of the new Electricity Regulation.

ISEA agrees with this position.

Consultation Question 4: It is proposed that any unit which is non-dispatchable but controllable and is no longer eligible for priority dispatch would run at their FPN, be settled at the imbalance price for any volumes sold ex-ante and could set the imbalance price.
As part of this proposal, there is a question of whether such units would be required to submit FPNs or where no FPN is submitted, the unit could be assigned a deemed FPN calculated by the TSOs as per the process today. Where a unit elects to submit an FPN, in this case, the TSOs would be required to use this as long as it does not deviate above a certain percentage of the TSOs' own forecast availability of the unit.
As an alternative or as a possible interim measure, taking account of the zero marginal cost nature of non-dispatchable but controllable generation in the market today, i.e. wind, solar, units no longer eligible for priority dispatch could be scheduled to their availability as per the process today on the assumption that this reflects economic dispatch in any case, but where there is excessive generation on the system such units would be subject to energy balancing prior to any priority dispatch units.
In particular, the RAs are seeking feedback from the TSOs on measures which can be introduced to facilitate required compliance with the new Electricity Regulation within the scheduling and dispatch and balancing market systems.

As noted in the main body of our letter, there are two risks at play here for a new generator:

- If a generator has to integrate with any materially changed system operation structure, this leads to CAPEX and delivery risk. Cost risks, in terms of new development or reconfiguration of equipment (which needs to be factored into a fixed price offer in the case of RESS participants) and timeline risks which are particularly critical for generators which have fixed delivery timeframes (as is the case for RESS participants). Whatever is decided, it must come at reasonable "business as usual" cost and be implementable by OEMs in a timely manner.

The second risk is that most renewable generators base their business model on the basis of their deliverable power, being their available power being downward redispatched for constraint and curtailment. In time, it will be known what degree of compensation will be paid for such redispatch. For generators without Priority Dispatch, their ability to achieve a market position will also have to be considered. Generators do not expect, however, to deal with any procedural revenue risks around notifications to the TSO as to what level they expect to run.

If a generator has to forecast its available power to the TSO one hour in advance in the form of MW set-point FPN, that FPN is respected in dispatch, but that FPN was below available power, then procedurally the renewable generator has inadvertently self-curtailed itself.

- There are many different solutions to this issue, e.g. FPNs in the same format as the instruction to the generator respecting that generator's technical characteristics, automated real-time updating of FPN closer to real-time post gate-closure, etc.

ISEA believes that this is an area which will require much further work before a decision is reached, and care must be taken with any hastily implemented interim solutions.

Consultation Question 5: Feedback is invited from interested stakeholders on the treatment of non-dispatchable and non-controllable units.

ISEA believe that this class of generator is outside the scope of dispatch and redispatch as they do not receive any control signals from the TSO and are therefore outside the scope of this consultation.

Consultation Question 6: Do you agree with the RA's interpretation that new generators which are no longer eligible for priority dispatch (both dispatchable

and non-dispatchable but controllable) will be subject to energy balancing actions by the TSOs, considered in dispatch economically and settled like any other instance of balancing energy?

ISEA agrees, but please note our response to Question 1 where clarity is required on the delineation between energy balancing and dispatch.

Consultation Question 7: What is your view on the application of bids and offers to zero marginal cost generation?

We believe that in dispatch:

- Priority Dispatch generators should be treated equivalently as today.
- Non-Priority Dispatch renewables should be treated equivalently to conventional generation, i.e. unregulated simple offer and complex offers regulated under the BMPCOP

In market settlement, we note that if the T&SC algebra is to be used for compensation for curtailment redispatch (effectively using market systems for compensation for non-market redispatch), the SRMC complex offers required under the BMPCOP (or the deemed market price of zero for Priority Dispatch renewables) are not appropriate to use as they will undercompensate generation.

Consultation Question 8: What is your view on a potential rule-set being implemented for non-dispatchable units where (a), systems cannot facilitate ranking of decremental bids for such units for balancing actions for a certain time period and/or (b) where convergent bid prices require a tie-break rule?

For energy balancing, it is expected that most renewables will have divergent prices as they are not regulated under the BMPCOP, so the issue might not be a severe as presented in the consultation. Nevertheless, tie-break situations will exist and should be managed pro-rata where possible.

Consultation Question 9: Do you agree with the TSOs' proposal for a revised priority dispatch hierarchy? The RAs request that the TSOs consider the points raised in this Section in their response with any further proposed changes to the hierarchy.

We concur with IWEA's response in relation to this matter.

We would like to add that it has become increasingly difficult to ascertain what are the combined legal obligations on the TSO to minimise downward redispatch of renewables under Article 13(5) (suggesting countertrading on Interconnection remains a legal requirement), with the requirements of TSO-TSO coordination under the Network Codes (which might restrict such activity). The market is still unable to influence interconnector flows intraday post intraday auction gate closure.

Until such clarity is given, ISEA cannot support the removal of all references to TSO countertrading from the hierarchy.

Consultation Question 10: Feedback is requested from interested stakeholders on the types of demonstration projects that may be suitable for an application process for limited priority dispatch eligibility.

We support IWEA's response in this matter.

Consultation Question 11: The RAs' interpretation of the Regulation is that where a new connection agreement is required or where the generation capacity of a unit is increased, a unit will no longer be eligible for priority dispatch. The RAs also propose that units should be able to make a choice on whether they wish to retain their priority dispatch status or not. Feedback is requested on this proposal.

Please refer to the main body of our letter.

Consultation Question 12: Do you agree with the RAs' interpretation of Article 13(5)(b) whereby downward redispatching of electricity produced from renewable energy sources or from high-efficiency cogeneration (i.e. the application of constraints and curtailment) regardless of priority dispatch status, should be minimised in the SEM? Under this interpretation, the only difference between renewable generators and HECHP eligible for priority dispatch will be how they are treated in terms of energy balancing.

The first sentence is important. There is a requirement on the TSO to minimise downwards redispatch of renewables. Within any market-based dispatch hierarchy for constraint – particularly one which is regulated under the BMPCOP – it is not clear how this can be ensured. ISEA therefore agrees with the IWEA position that constraint (as a form of redispatch) sits better as non-market based redispatch.

Article 13(5)(b) requires all non-renewable non-HE CHP generation to be downward redispatched in advance of any renewable, irrespective of the price offer by those renewables to do so.

ISEA would also like clarity whether it is the SEM Committee's intent to reinterpret Priority Dispatch as only being relevant to energy balancing, i.e. if Priority Dispatch and non-Priority Dispatch are treated the same, and constraint is market based redispatch, then do Priority Dispatch generators compete on price to resolve constraints where downward redispatch is involved?

ISEA would not support such a redefinition of Priority Dispatch.

Consultation Question 13: Do you agree with the RAs' interpretation of Article 13(6) and the introduction of a new hierarchy for the application of non-market-based downward redispatching?

We support IWEA's response in this matter.

Consultation Question 14: Do you agree with the RAs' interpretation of Article 13(7) and the view that the provision of financial compensation to firm generators subject to curtailment based on net revenues from the day-ahead market including any financial support that would have been received represents an unjustifiably high level of compensation?

ISEA does not agree that the cost of compensation is unjustifiably high and agrees with IWEA's interpretation that the compensation cost referred to is not an industry wide assessment, but rather whether a generator has been over or under compensated.

ISEA notes that the SEM Committee have used the rationale of a "limited budget" to integrate renewables into the SEM in order to deny the rights of renewable generators for compensation for redispatch. ISEA are surprised by such an argument, given that the minimisation of the downward redispatch of renewables is a legal requirement under Article 13(5). ISEA seeks clarity from the SEM Committee as to the rationale for any such budgetary limit and would like some transparency as to what quantum of revenue is envisaged, along with the rationale for the choice of that amount.

Consultation Question 15: Which of the options on compensation for curtailment presented above do you view to be most appropriate to adopt in the SEM? Are there additional options that the Ras should consider around compensation for curtailment?

We support IWEA's response in this matter. ISEA is reluctant to engage with potential mechanisms for downward redispatch which don't provide its members will the full compensation to which it is entitled.

Nevertheless, ISEA notes that compensation mechanisms which facilitate certainty (such as full compensation) that can be incorporated into forward looking financial modelling are strongly preferred. Any mechanism, for example, which cannot be settled end-of-month should be rejected, e.g. annual threshold targets which need to be evaluated on a cumulative rolling basis. Such mechanisms can leave generators (and their off-takers) uncertain as to what compensation has been paid until the end of a reconciliation period. A financial compensation designed to reduce risk should do its best to avoid procedural cash-flow and predictability uncertainty in its implementation.