ElectroRoute Energy Supply Limited
Marconi House, Digges Lane.
Dublin 2. D02 TD60

T: + 353 (0) 1 687 5700
E: info@electroroute.com
W: www.electroroute.com

22nd June 2020

Response to Consultation SEM-20-028: Implementation of Regulation 2019/943 in relation to Dispatch and Redispatch

Summary of Response

We appreciate the opportunity to respond to the Consultation. At a high level, our understanding of Regulation 2019/943 (henceforth referred to as "the Regulation") is that it is designed to better enable electricity markets to incorporate large shares of non-dispatchable but controllable generation (e.g. wind and solar) and facilitate the improvement of grid flexibility and infrastructure to ensure renewable electricity generation is maximised, in line with EU policy and targets. We believe it intends to do this by ensuring systems are dispatched based on the **economic merit of all participants** and that the market is used effectively to determine this. To this regard, it outlines the framework to steer all participants towards **active involvement** in the electricity market, most evidently displayed by the removal of priority dispatch for future generating units. It also seeks to ensure TSOs, DSOs and NEMOs are aware of their obligations to **maximise renewable electricity generation**, ensure **system dispatch is market based** and, where non-market based decisions must be taken, **fairly compensate units** for the TSO's inability to use the market to dispatch the system. Therefore, the implementation of the Regulation to the SEM should be motivated by a need to meet these obligations.

The RAs should follow an approach which ensures non-priority units are instated as active market members, with the **same responsibilities and opportunities** that any dispatchable unit currently has or would have in the future. For this reason, non-dispatchable but controllable units should be permitted to submit FPNs that will be accepted by the TSO and afforded the chance to control their dispatch position through the submission of simple and complex commercial offer data (COD), just as their dispatchable counterparts can. Generators which are subject to non-market based redispatch should also be **entitled to the compensation** that the Consultation

unequivocally states they should receive. On this note, we believe the RAs' assessment of the "*unjustifiably high*" cost to the consumer for compensation of non-market based redispatch to be categorically incorrect.

Crucially, we believe that these changes should be agreed upon and implemented as an **urgent priority** in order to avoid unnecessary confusion and uncertainty for future renewable electricity projects in particular, but also the wider industry. Lengthy delay would only serve to hamper the development of renewable electricity on the Island of Ireland and undermine the overarching principle of the Regulation.

Response to the 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?*

Response to Question 1:

We agree with the RA's interpretation of dispatch and redispatch outlined in Articles 12 and 13 in the context of the SEM. However, we have concerns about the distinction between market and non-market based redispatch.

On Page 13, the difference between market and non-market based redispatch is described as whether the decision "*follows an economic merit order or not*". In line with this, we agree that at present, curtailment in the SEM (defined as "the dispatch down of non-synchronous generation for system wide reasons, where the dispatch down of all such generators would alleviate the problem" on Page 12) can be regarded as non-market based redispatch because Commercial Offer Data is not considered in the decision to redispatch generators – hence no economic merit order.

However, it should be noted that there are already inherent market-based influences on the volume of curtailment redispatch: for instance, the interconnector flows are set by the results of the ex-ante markets and play a large role in the volume of curtailment due to interconnector schedules having a higher priority than non-synchronous generation. During periods of high wind, where prices are also depressed in Great Britain, the price at which wind is willing to sell into ex-ante markets at will affect interconnector flows. Another consideration is that generators are not all equally willing to be curtailed. For example, one generator may want to turn completely off if the price is below a certain level and generate nothing, and another may want to generate its full availability. Under the current approach, both will be turned down pro-rata, leaving both units generating a portion of their availability with neither satisfied. Using a market-based approach (by allowing units to submit bids reflecting their willingness to be curtailed) would address this problem.

We agree to an extent that redispatch due to the application of system constraints has an economic merit order if the units involved in the constraint are redispatched solely based on their Commercial and Technical Offer Data (COD & TOD). However, as soon as a constraint causes redispatch of a unit that does not submit COD or TOD (i.e. non-dispatchable generation), then the decision is not following an economic merit order, and hence by the RA's own view cannot be market based.

A fix to the distinction between market and non-market based redispatch would be to ensure that all redispatch is market based by taking COD from all non-dispatchable generation into consideration in both curtailment and constraint decisions – hence, all decisions follow an economic merit order. We believe the Regulation intends to move European electricity markets in this direction.

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

Response to Question 2:
Our view is that active projects which have energised since the 4^{th} July 2019, or are nearing completion of construction, which have a clear route to market and are actively making progress on financing and commissioning should have their priority dispatch status protected by the RAs. The most obvious measure of this is a project which can demonstrate evidence of a route to market, such as a REFIT Letter of Offer or a CPPA before 4^{th} July 2019. However, if a project became commercially operational under a different route to market (e.g. RESS instead of REFIT) it should not receive priority dispatch, as this represents an activation made after the 4^{th} July 2019.

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.*

Response to Question 3:
We agree with this understanding as these processes are already in place for many non-

renewable dispatchable units with priority dispatch.

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.

Response to Question 4:
The fairest approach would be to allow non-dispatchable units to submit FPNs to the TSO. This gives these units the greatest control over their output, which is much more relevant now due to the significant difference between RESS and REFIT remuneration mechanisms. For example, in the case of negative prices in the day-ahead market, a future RESS unit is unlikely to have a market position, despite possibly being available to produce. Under the current market operation, this unit would be forced to FPN at its full availability, exposing it further to negative prices in the balancing market with no prospect of receiving its subsidy for the power it produces, essentially forcing it to lose money. This would be grossly unfair and would be detrimental to the growth of renewable electricity on the Island of Ireland. A dispatchable generator would never be forced to declare its full availability as its FPN if it had no market position and suffer the consequences of a negatively priced market, and so to subject RESS or out-of-support units to this for any period of time would be discriminatory.

The argument for using wind FPNs is further motivated by the amount of "unnecessary turn down" of non-dispatchable controllable generation in the current balancing market. ElectroRoute has quantified the scale of this unnecessary turn down through calculations on historic market data (2019/01/01 – 2020/05/31). The results reveal that, had wind generator FPNs been determined by their ex-ante position rather than their forecast availability, the total "turn down" (the difference between the relevant aggregated wind FPNs and the scheduled wind generation output of the TSO dispatch processes) would have been dramatically lower. This is illustrated by month in Fig. 1.

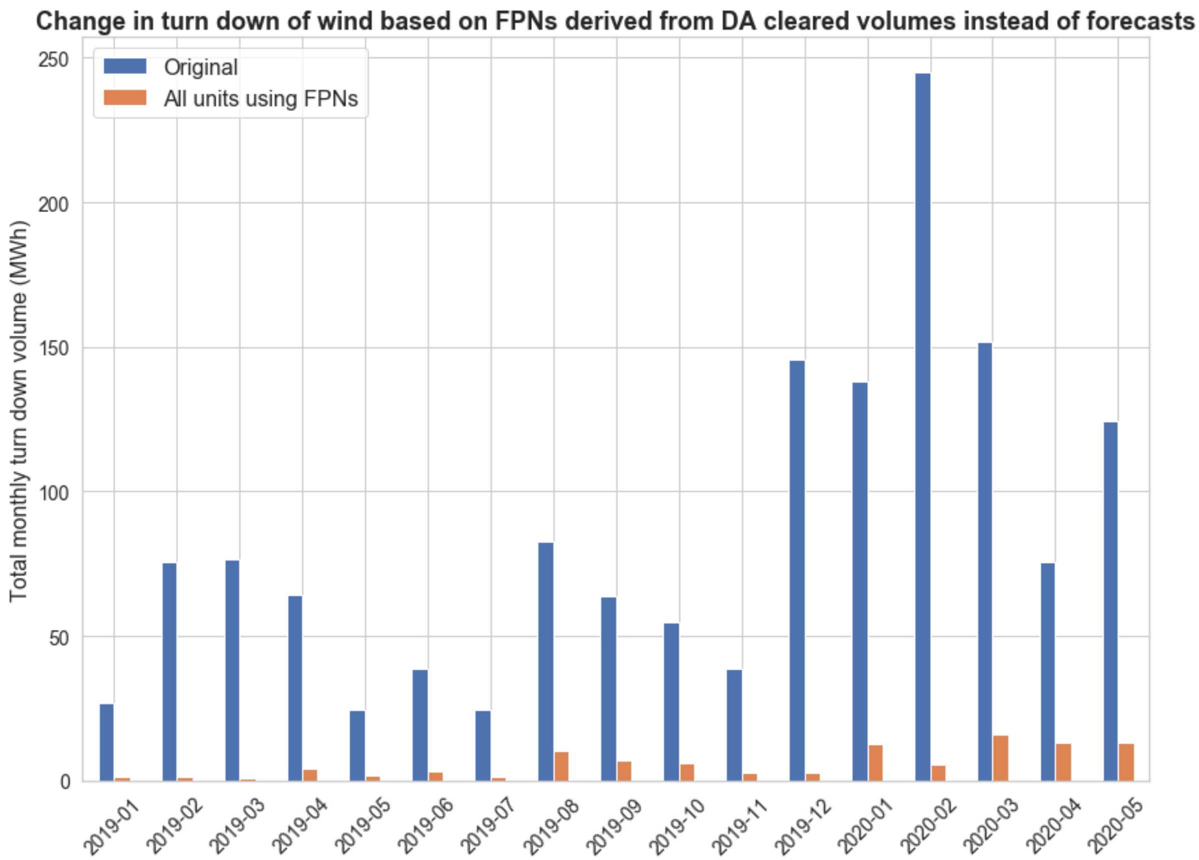

Fig. 1. Change in volume of wind generation turned down by using wind unit's DA position as FPN instead of forecast position. Turn down volume was calculated as the difference between the aggregated wind FPNs and the scheduled wind generation output for the time period, as determined by the TSO's scheduling and dispatch processes

The reason is because most of the turn down was for volume that did not clear in the ex-ante markets, and thus units were never expected to generate. This turn down does not represent an efficient balancing of supply and demand – the supply volume is falsified to a level that generators may not be willing to produce at. To demonstrate this falsehood, imagine an extreme situation in which every unit was always scheduled to its maximum availability irrespective of its ex-ante position, and then turned down to balance the system as required – it is very easy to see that this market design is inefficient. As we tend toward a market with potentially 70% renewable generation, the current use of forecasts for wind FPNs would lead to exactly this scenario. These turn down periods are usually associated with a cannibalisation of the balancing price (as wind generation is turned down for 0 €/MWh). Hence, allowing non-dispatchable, controllable units to submit their own FPNs reflecting their intended generation schedule will lead to less turn down in the balancing market, less price distortion and overall a more efficient market.

This FPN approach also leaves room for non-dispatchable units to be "inc'd up" in the balancing market, if the balancing price dictates it should, with the volume between their FPN and availability available. This could be facilitated using COD submitted by units reflecting their willingness to increase generation, in a similar way to dispatchable units, or simply by using the existing dispatch processes for wind generation and allowing for a potential increase in generation as well as decrease at the marginal price.

We also believe that this change to FPN submission should be made a priority and as such should take place as soon as possible, certainly before the first non-priority dispatch renewable unit begins operating in the market. Any delay in its implementation would greatly disadvantage RESS or out-of-support projects, hampering the development of renewable generation in Ireland.

A simple interim measure to ensure this timeframe is not breached would be to give any non-dispatchable unit which desired so the option to submit PNs that the TSO scheduling and dispatch processes would be required to use, instead of it being at the TSO's discretion whether to use them. For clarity, units which did not want to submit PNs would not have to and the current approach would be used to set their FPN to their availability. This would be a temporary change until widespread changes can allow these units to fully control their market behavior (including PNs and COD), as we believe the Regulation intends to set in place.

The requirement to accept a unit's FPN "*as long as it does not deviate above a certain percentage of the TSO's own forecast availability of the unit*" is ambiguous – what would the TSO use instead of the submitted FPN in this case? It is also not clear why this statement is included – why can the TSO ignore an intended generation position because it is higher than their forecast? It would be useful to have more clarity on how these limits would be formulated, especially considering there are times where there is a large divergence between forecasts from various third-party providers (the exact timing of a ramp up in wind from a large weather system for example).

It is not explicitly stated but it might be implied that units without priority dispatch and marginal costs of zero are immune to negative prices in the balancing market, as they would be dispatched down to off before any negatively priced actions would be accepted. This is not necessarily true, but it shouldn't matter whether a non-priority dispatch unit is immune to negative prices or not as it is not a price-taking unit. It should not be assumed that just because a unit has zero marginal costs it is willing to generate for any imbalance price greater than or equal to 0 €/MWh; this is fundamentally incorrect. As a price-making unit, it is at the unit's discretion whether it generates or not for the price available, in the same way dispatchable units currently have this discretion in the form of the simple COD they submit. To not offer this discretion to non-priority units with zero marginal costs would be discriminatory.

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

Response to Question 5:

As these units are not required to be dispatchable and are permitted to run their own schedule at their discretion to the limits of their connection offer, we believe that Articles 12 and 13 do not apply to these units and therefore no change is required to these generators.

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?*

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

Response to Question 6 & Question 7:

We agree with this interpretation, as long as all non-priority dispatch generation (both dispatchable and non-dispatchable but controllable) have equal responsibilities and opportunities in the balancing market. Anything else would be discriminatory.

This would mean that, as dispatchable generators can submit complex (marginal) and simple (non-marginal) COD, non-dispatchable units without priority dispatch (now treated as equals to conventional units in the eyes of the market) should be allowed to submit the same. The Regulation intends to create efficient competition in electricity markets with increasingly larger shares of non-dispatchable generation – if they are not offered the same opportunity as their conventional counterparts, this cannot happen.

Therefore, the implementation of processes to allow these units to submit the relevant data to facilitate equal opportunity is a necessity to avoid market discrimination. The comments from the TSO on the difficulties of implementation of COD for wind units (Page 33) are irrelevant. The TSO should be capable of updating systems to accommodate this going forward and this issue should not be used as a barrier to change.

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?*

Response to Question 8:

Our view is that there should not be a time period when systems cannot facilitate ranking of decremental bids, otherwise there is market discrimination between certain units within the non-priority category. In the treatment of convergent bid prices, the application of actions on a pro-rata basis is the fairest outcome available.

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.

Response to Question 9:

We agree with the revised priority dispatch hierarchy outlined on Pages 34-35 from points 2-6, but are concerned by the inclusion of the use of SNSP restrictions to set a market position in point 1, as the consultation does not provide any details on how the SNSP limit would influence how units are dispatched. It should be noted that there is an interdependency between the trading behaviour in the ex-ante market and the SNSP level. The interconnector flows heavily influence the SNSP calculation and these flows are determined in the ex-ante markets. This dynamic would need to be carefully considered in any regulation that requires the SNSP limits to be considered in trading decisions by participants.

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.*

Response to Question 11:

The Regulation is very clear on the point that a unit forfeits priority dispatch when a new connection agreement is made or generation capacity is increased. However, the interpretation of "significant modifications" is important as it could inadvertently prevent efficient forms of further renewable development where possible to do so. We would therefore advocate as much flexibility as possible in what constitutes a "significant modification" to a grid connection to avoid this unintended consequence.

We do believe that units should be able to make a choice on whether they wish to retain priority dispatch status, and that the choice to forfeit should be available to the unit at any point in time.

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.*

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?*

Response to Question 12 & Question 13:

The Regulation is very clear that the downward redispatching of these units should be minimised. The hierarchy proposed does correctly identify the correct order units should be downward redispatched for non-market-based downward redispatching.

However, this should not be done at the expense of *Article 13(5)(b)* and *Article 13(5)(c)*, which makes clear that appropriate grid-related measures should be taken to minimise non-market downward redispatching of these units and requires TSOs and DSOs to ensure their networks are sufficiently flexible. Measures should be taken over the next decade to ensure the grid is improved to minimise downward redispatching without solely relying on the hierarchy.

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?*

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?*

Response to Question 14 & Question 15:

There are many things we do not agree upon surrounding the RAs' interpretation of *Article 13(7)*. Firstly, on Page 46 it is claimed there should be "*no distinction between old and new renewable generation under Article 13 for the purposes of the application of curtailment*". In keeping with the notion that non-dispatchable controllable units without priority dispatch are now equivalent to conventional generators in the eyes of the market, it is our opinion that these units should be afforded the opportunity to influence their likelihood of redispatch for curtailment reasons through the complex and simple COD submitted to the market operator, just as conventional units can do with system constraints they are part of. Not to allow this would be discriminatory to these units.

Secondly, the analysis conducted which suggests the compensation to which curtailed generators are entitled under *Article 13(7)* places an undue burden on electricity consumers and the decision of the RAs that the level of compensation is unjustifiably high is both incorrect and unlawful for several reasons:

- The graph presented in Figure 6 (Page 51) showing the monthly compensation for curtailment is flawed because it does not account for the new approach of submission of FPNs and COD data from non-dispatchable units, as opposed to the use of forecast availability. This will ultimately lead to lower curtailment values compared to the current approach and hence less compensation
- The estimation of future curtailment compensation through "*scenario analysis*" is presented as simply a number on Page 50. The modelling process must be explicitly outlined so the reliability of this figure can be assessed. There is an abundance of factors which could mean this figure is lower than calculated – cannibalising day-ahead market prices due to increased share of renewable generation or uncertainty about upcoming RESS project strike prices, for example. Without the presentation of evidence on how these scenarios were modelled, this figure cannot be taken at face value
- It is not clear at what point the costs become "*unjustifiably high*" to the consumer. Would any extra cost to the consumer have been considered too high?
- It is our view that *Article 13(7)* is designed in large part to deter non-market based redispatch. It places the onus on the TSO and DSO to improve the system to such an extent that large amounts of redispatch does not occur (and hence the compensation paid will be low) and allows generators to receive fair compensation for a system which is not fit for purpose. To ignore this compensation would be to ignore this requirement to sufficiently improve the system
- Finally, this is an EU regulation, meaning it is binding in its entirety and is directly applicable without the need for any national legislation. It therefore supersedes any obligations of the SEM committee and must be strictly implemented in its entirety. The reference to unjustifiably low/high compensation in *Article 13(7)* also appears to have been misinterpreted by the RAs – this is a test of whether *the generator* is overcompensated or undercompensated based on its redispatch, not whether the compensation to which the generator is lawfully entitled is, or is not, an unjustifiable burden on anyone else. If this were not the case, the Regulation would be suggesting that it would be possible to have an unjustifiably low financial burden on consumers, which doesn't make sense. Hence any decision which rejects compensation for redispatched generators based on the impact to

consumers is both incorrect and unlawful

As a result of this flawed interpretation and analysis, none of the proposed options in section 4.5 can legally be implemented or given credence.

General Comments

We would like to express our concern at the length of time it appears it may take to fully implement this regulation into the SEM. This regulation has been published since June 2019, and has been applicable to Irish law since January 2020, yet this is the first consultation on any of its implementation in the SEM. Given the current timing of system software releases, it looks very possible that it may be April 2022 at the earliest before any market changes take place. This is despite the fact RESS auctions are due to take place later this year, and the huge implications that decisions on this consultation and implementation of the Regulation in general will have on projects which receive a RESS contract. The delay in the proper implementation of the Regulation in the SEM is causing huge uncertainty with potential RESS units: in the price they bid into the auction and in their negotiation of contracts.

We would urge the RAs, the TSO and the SEM Committee to work to deliver a market which is compliant with the Regulation as a matter of urgency in order to support the accelerated development of renewable and flexible generation in Ireland, particularly those which will soon participate in the market without priority dispatch.

Conclusion

There is an obvious need to reassess the issue surrounding compensation of non-market based redispatch, as the analysis and conclusions drawn in the Consultation are fundamentally wrong. While we welcome that the Consultation appears to favor the introduction of FPNs for non-dispatchable, controllable generation, we again stress these units should be treated as equals to dispatchable units in all their market responsibilities and opportunities. There is certainly much more work to do to fully implement the Regulation in the SEM, and this Consultation should serve as the first step in that process, not as the last. The Regulation provides clear obligations to be met by the RAs, TSO and DSO and ultimately the solution to meet these should be informed with primary influence from those who will be most affected by the changes (i.e. new renewable generation, priority dispatch units and new flexible generation).