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For the attention of: Gina Kelly and Gary Mccullough

Cloosh Valley Wind Farm DAC – Clean Energy Package Consultation

Introduction
Cloosh Valley Wind Farm DAC ("***CVWF***") welcomes the opportunity to comment on SEM-20-028 Implementation of Regulation 2019/943 in relation to Dispatch and Redispatch. For the avoidance of doubt, this is a non-confidential response.

CVWF is a joint venture between SSE and Greencoat responsible of the operation of the 108 wind farm within Galway Wind Park.

The Clean Energy Package contains a wide-reaching set of requirements impacting market design and the operation of both new and existing generation in the market. Most specifically, the treatment of curtailment, future of priority dispatch and the interpretation of non-market redispatch ahead of the RESS auction; as well as the potential method for recouping the costs of implementation, i.e. imperfections, PSO etc.

CVWF Response
CVWF has provided a general response and specific responses to some the 15 consultation questions posed in the paper relevant to the business of CVWF. Under our general response below we have provided comments on stakeholder engagement as noted below.

Stakeholder Engagement
We welcome the significant engagement undertaken with industry over the last number of weeks to field questions and provide clarity on the context and background of this consultation. We would request that this approach continues during the course of developing and implementing the solutions that will deliver compliance with Article 12 and 13. We acknowledge from discussions that the purpose of this consultation is to indicate areas we consider require further consultation, which we have outlined below.

It is also encouraging that a working group was established to facilitate discussion on the implementation of Article 12 into the SEM. We advocate a similar working group is established to discuss the implementation of Article 13.

We note that currently the priority dispatch working group exploring Article 12 implementation does not carry any agency with regard to the development of a solution. We would advocate that since this group was developed with the members of the Trading and Settlement Code Committee and observers as its original members, it should be allowed to develop and deliver a roadmap of specific code modifications and system solutions to implement Article 12. Furthermore, it should be the forum where SEMO can update industry when they are progressing with the interim or enduring solutions to the systems and provide opportunity to interrogate and test the solutions being delivered. A similar role should be provided to the parallel working group considering the implementation of Article 13 within the ISEM market.

We would also advocate for a separate workshop over the summer period to discuss the interactions between Article 12 and 13 as this is one area, we feel has received little attention to date, e.g. PSO, RESS, Connection Policy and other interactions. We appreciate that everyone is working in a different environment given the pandemic situation, however, these requirements will span the full spectrum of market activities and will take some considerable time to interpret appropriately for our market; we need a structured and consistent mechanism for collaboration and engagement.

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?

We acknowledge the interpretation of the requirements under Article 12. We note the interpretation of the eligibility criteria raised in subsequent consultation questions below, arguably widens the intent of the requirement under Article 12 for priority dispatch, where the intention is that priority dispatch must not pose or contribute to discrimination in the market.

With regard to Article 13, we agree that market-based dispatch needs to take account of the commercial and technical offer data submitted by participants. As it stands no priority dispatch unit is capable of submitting commercial or technical offer data that will be used to minimise the cost of diverging from an ex-ante schedule. Additionally, there is no ability, currently, for non-priority dispatch renewables to submit such data. Therefore, in the absence of this ability in the market, all redispatch of renewable generation is non-market based.

There is confusion in the consultation as to what constitutes redispatch. The consultation appears to indicate that only the real-time actions taken by the TSO are redispatch. Yet under market-based redispatch it is indicated that any action taken by the TSO is market-based redispatch. We would contest that all actions that do not take account of commercial and technical offer data are non-market based. As it stands Physical Notifications (PNs) and commercial and technical offer data from wind units are not considered as part of the market solution, therefore both constraints and curtailment for these units must be non-market redispatch.

Article 13 clearly states that dispatching shall be based on objective, transparent and non-discriminatory criteria. It is not clear yet how the RAs are proposing to ensure that this requirement is implemented so as to allow all generation regardless of priority dispatch status to be able to participate in the SEM in the same manner. This would appear to include permitting the submission of technical and commercial offer data for all units that is used to balance the system.

Redispatch is defined in the regulation as: means a measure, including curtailment, that is activated by one or more transmission system operators or distribution system operators by altering the generation, load pattern, or both, in order to change physical flows in the electricity system and relieve a physical congestion or otherwise ensure system security.

This would therefore indicate that redispatch include both constraint and curtailment as understood in SEM. Further work is needed in the interpretation of Article 13 as it applies to the SEM and the specific configurations of our market.

Finally, we note that where curtailment is proposed to be too expensive, coupled with historic lack of significant grid investment to reduce curtailment volumes—creates an untenable situation. Grid investment is avoided, constraints remain and increase, and curtailment compensation is not also provided. Curtailment will likely continue with higher degrees of non-synchronous generation on the system and lack of investment to reduce local constraints. We would strongly advocate that this must be considered together.

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.

We have concerns that the proposed criteria for eligibility proposed above, risks broadening the scope of eligibility further than would be prudent.

We would not be in favour of the concept of relying on a commissioning programme agreed with the TSO, unless it is made mandatory for TSOs to provide these programmes for all projects. At the moment, this is not the case and therefore this cannot be a utilised as a constant criterion for priority dispatch eligibility.

Equally, the use of a criterion based on “eligibility to be processed to receive a valid connection offer” is itself an eligibility threshold, i.e. a process has been undertaken to determine eligibility for processing of a connection offer. It is not prudent to use the non-binding criterion of whether a project could get a spot in the queue for likely receipt of a connection offer. This would leave room for abuse to anyone who is sitting in the queue to hold onto their spot in an effort to retain priority dispatch. In addition, given that connection offers can be delayed due to system issues, this would not be a certain enough criterion. In discussions at bi-laterals with the RAs, it was indicated that there was no specific capacity intended to be accommodated when raising this potential eligibility criterion. Thus, no specific context or basis for this approach. We cannot support such a subjective criterion.
In principle, the use of a REFIT letter of offer or PPA are well-understood and therefore, are suitable criteria to demonstrate eligibility. We would encourage further discussion and consultation on the criteria for eligibility.

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.
One of our shareholders (SSE) have engaged in the SEMO workshops discussing the implementation of Art 12 and a potential interim solution, before an enduring system change can be provided. The interim solution appears to suggest that where priority dispatch is lost, these units will be treated more like other dispatchable units. We take this to mean that submission commercial offer, technical offer data and FPNs would be expected. It is important that currently, INCs data cannot be provided and this needs to be factored into any consideration of how these units can be treated and can operate more like dispatchable plant.

For new generation, the loss of priority dispatch, is understood to be an inevitability. However, the unacknowledged priority dispatch relating to locational constraints and must-run plant must also be addressed in order to ensure a completely level field in the SEM. Insofar as existing units, we appreciate the intention to allow for units to opt out of priority dispatch, however, we hope that this opt out can remain discretionary. In the current heavily constrained market with high degrees of dispatch down, there is a perception that the loss of priority dispatch will result in higher risk of curtailment of those existing units that would otherwise have the protection of priority dispatch.

A centrally dispatched system without priority dispatch also introduces issues where there are prevailing negative prices and a RESS scheme that will also not provide supports where there are negative prices. There needs to be a mechanism where units can self-dispatch down to reduce exposure to negative prices.

Therefore, as part of this implementation, a method for self-dispatch must be explored alongside a process for opt-out, before it can be clear to market participants what the benefits of seeking to be treated as dispatchable, might be. This area clearly needs further discussion and consultation.
Discussion and consultation in this area must include solutions for the following:

- How wind units can self-dispatch in a way to ensure they can be dispatched down at times of negative prices to avoid the loss of RESS supports, as well as the exposure to negative prices.
- The impact of Mod 10_19 Removal of negative QBOAs related to dispatchable priority dispatch units from the imbalance price. This has been approved and is awaiting system release, but given the subject matter relates to priority dispatch and hierarchy, needs to be considered as part of the implementation of the requirements of Article 12. We imagine there will need to be a similar consideration of any other relevant new code modifications, as well as changes to the existing version of the Codes.
- Those units that retain priority dispatch should equally be able to reduce their exposure to negative prices and signal through PNs on occasion, that they wish to be dispatched down—rather than having a static dispatch hierarchy that will now expose a gradually smaller group of wind units to negative prices in the market.
- Finally, true merchant assets that do not get the same supports, are also in the same situation in a centrally dispatched system, where they are forced to sell energy every day, even during negative prices and cannot self-dispatch down.

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. It is assumed that this question is referring to the fact that where there is any deviation in volumes, these deviations for such a unit should be settled at the imbalance price; rather than for any volumes. On that basis, we can acknowledge this approach. In general, the treatment of wind units as dispatchable needs significantly more discussion and consultation to arrive at a solution that resolves the complexity involved.

For instance, the system burden for smaller market participants in submitting greater levels of data and operating closer to a 24/7 operations desk must be surveyed and considered as part of the solution. The RAs have confirmed that "deemed FPNs" were suggested as an option that could be retained for those smaller units who do not have the resources to provide this level of operations for their assets. This is welcome. It demonstrates that this burden is already acknowledged. However, the uncertainty around which system would be suitable, i.e. EDIL, Wind Dispatch Tool or some other 3rd option still needs to be considered. At the same time, this retained practice could create an unfair situation if it is not carefully considered as a temporary facilitation to allow a greater move towards a non-discriminatory market in line with Article 12. Therefore, it should have specific conditions attached to it, and a framework to help market participants over time move towards the market envisaged under the Regulations.

Finally, we note the request for the TSO to provide a response specifically under this question. Therefore, in the absence of this response, this area of compliance under Article 12 does not have sufficient detail for us to be any more definitive. This would merit further discussion and consultation. As above, we would suggest that the solution for this question should be part of the SEMO priority dispatch workshop, which can also consider the TSC and system impacts of these changes.

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

In principle, it appears reasonable that these units continue to be treated as they are currently, in the market. However, it should be considered what criteria should exist for these units, to ensure that otherwise dispatchable units do not opt to re-register under this designation if it proves easier.

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?

There is not sufficient clarity as to how this will operate in practice, to be able to respond to this question. In certain circumstances, this may be the right course of action, but without sufficient detail at this stage—this should be reviewed as part of a separate consultation on the dispatch hierarchy and methodology as impacted by Article 12 and 13.

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

Initial view is that if a unit that loses priority dispatch is treated as a dispatchable unit, it is expected that these units would be expected to submit bids and offers like other units. However, it is not known the effect and application of this approach, where it is clear that these units currently cannot submit this level of information at this time. Therefore, it is not clear at this moment whether this would be favourable principle or not, without an understanding of how this will be applied in the interim and enduring scenarios as outlined by SEMO.

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?

There is no clarity on the grounds on which a tie-break would be applied and what a tie-break would mean in practice. We would be supportive of needing to have a tie-break solution for specific circumstances, but without clarity on what the specific situations are, we cannot comment further. Therefore, we expect this would also be an area to be consulted upon as a clear proposal is developed.

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.

It is understood that the relevant dispatch hierarchy intended is not yet confirmed. As noted by the RAs, the hierarchies in this paper also conflict and therefore this has raised confusion in the industry. On this basis, we expect that the dispatch hierarchy will require to be consulted on separately.

We also expect there to be further response from the TSO as to what dispatch hierarchies may be possible. We note the interaction the dispatch hierarchy will also have with the tie-break approach in question 8 above and expect these two activities will need to be considered together. Finally, we expect some consideration of how the dispatch hierarchy may need to be flexed as the implementation of Article 12 develops over time.

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.

Greater clarity is needed as to the definition of "significant modifications" that necessitate the issuing of a new connection agreement. Connection policy lacks significant transparency and clarity around process and threshold for minor amendments to existing connection agreements. The connections process and policy in other jurisdictions provides clarity such that generators can know what actions would disqualify them from certain benefits, and what won't.

This is a key consideration for the retention of priority dispatch by units who may wish to optimise generation at their site, but may avoid doing so, because of the potential loss of priority dispatch. Repowering and optimisation of existing sites, is one efficient way to seek to optimise the grid and reduce some network investment—therefore this should be facilitated and clearly outlined without undermining this valuable contribution to grid, by triggering the removal of priority dispatch.

We agree that generators should be provided the option to opt out of priority dispatch.

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 interpretation of re-dispatching is vitally important to being able to understand the current position of the RAs. It is CVWF's view that further work will be required to set out and establish the interpretation of redispatch in the context of SEM. Section 1.2 sets out that redispatch includes any move away from PNs for generating units. In addition to this, those units which do not submit PNs or bids or offers in to the Balancing Market are subject to non-market redispatch, which would include any changes to the physical flows from the deemed PNs for wind/solar generation, regardless of being for system constraint or curtailment.

Subject to further consultation to define redispatch in the context of SEM, CVWF agrees with the principal that downward re-dispatching of renewable generation should be minimised. However, it is not clear yet how the RAs intend to meet the requirements of 13(5)(a) specifically with reference to re-dispatching not exceeding 5%.

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?

This needs to be read in conjunction with Consultation Question 9 to ensure consistency. This proposal would appear to reflect the requirements of the Regulation, however there is further consultation required over non-market based redispatch. As those units that are currently subject to priority dispatch do not submit bids and offers for the purposes of the balancing market and therefore all actions taken to change the physical flows of these units would then become non-market based.

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?

The regulation is quite clear that compensation shall be subject to financial compensation where a firm generator is redispatched. "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."

Contrary to the position set out in the consultation paper, Article 13(7) requires compensation to be paid rather than "allow for compensation to be provided". It is up to the Member State to set out why this cannot be paid.

There is insufficient evidence in the consultation to support the modelling presented and therefore we are unable to comment on this in a meaningful way. It is CVWF's view that the RAs are required to pay compensation, and in order to avoid paying compensation they must fully justify why the compensation is either too high or too low to market participants.

Based on the consultation paper we are of the view that the RAs have not provided sufficient rationale or robust modelling to justify the proposed position. We therefore feel that it is incumbent on the RAs to carry out further studies on the potential impact and consult on the basis of those findings along with any modelling assumptions.

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?

There has been considerable work carried out to date that has contributed to reducing the deviation between the ex-ante market schedule and the physical flows on the network. We are of the view that Article 13 has the ability to reduce the risk, and therefore costs, of renewable generation both existing and future. Option 7, in principle, is what we should be striving towards accepting, though there are a number of steps along the way.

We trust that this feedback is helpful to you and would be happy to discuss further and kindly request to be updated on the progress of this consultation and the next steps towards implementation of the Clean Energy Package.

Richard Scott,
General Manager

For and on behalf of Cloosh Valley Wind Farm DAC