Implementation of Regulation 2019/943 in relation to Dispatch and Redispatch

Consultation Response from

BORD NA MÓNA
Naturally Driven

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1. Introduction

Bord na Móna (BnM) welcome the opportunity to respond to the SEMC consultation paper "Implementation of Regulation 2019/943 in relation to Dispatch and Redispatch".

Firstly, it is important to note that EU regulations are legally binding acts of the European Union and are directly applicable in all Member States of the European Union. Implementing regulations in Member State jurisdictions take precedent over national legislation. Implementing regulations in Member States are always limited in scope. Furthermore, implementing regulations are directly applicable and do not need to be transposed into national legislation.

The Regulation that has given rise to this consultation is part of a wider legislative package, the Clean Energy Package for All Europeans, that sets a target of at least 32% in renewable energy by 2030 and seeks to integrate renewables into the grid and manage risks. This Regulation has several stated objectives, including, but not limited to:

- Removal of State interventions and market distortions in the European wholesale electricity market, including priority dispatch.
- Maximise of the use of electricity generated from renewable sources or high-efficiency cogeneration.
- Require TSOs and DSOs to guarantee the capability of their respective networks to transmit electricity produced from renewable energy sources or high-efficiency cogeneration with minimum possible redispatching.
- Promote market-based electricity trading and balance responsibility.
- Complete the effective integration of renewable energy into the internal energy market to drive investments in the long term and contribute to delivering the objectives of Energy Union and the 2030 climate and energy framework.

The specific Articles that are the focus of this consultation are Articles 12 and Article 13. Article 12 requires all new generation to participate in the market on the same basis as conventional generation and and for the use of electricity from renewable sources or high-efficiency cogeneration to be maximised. Article 13 requires a market-based system for redispatch but where such a market does not exist, it stipulates that generators must receive full financial compensation. It is important to note that the Regulation entered into force from the 1st January 2020.

While the publication of this consultation is welcomed, and since the I-SEM market has not received a derogation from the implementation of both Articles 12 and 13 that it is required by European law to be compliant with both Articles from 1st January 2020. It is therefore, paramount that no further time is lost and a clear road-map to implementation of Article 12 and 13 is given as soon as possible.

Notwithstanding the need for expediency, a roadmap should include, as a minimum, the path and timings to implementation of an interim solution, an enduring solution, and the proposed back-dating date of any payments due. These are needed to give clarity to the Market Operator, System Operator and Market Participants on the RAs position and subsequent market tools and code changes needed, as well as for consideration in upcoming RESS auctions and commercial decision making of market participants.

In this response, Bord na Móna, has identified several high-level principles which frames how this Regulation must be incorporated into the day-to-day operation of the SEM.

2. Article 12

2.1 Treatment of non-priority dispatch renewable generation

Under Article 12, new renewable generators which are not eligible to obtain priority dispatch would become responsible for submitting Commercial and Technical Offer Data (COD and TOD) and respond to dispatch instructions from the system operator. Importantly, under Article 12 there is also provision for the priority dispatch status of renewable generation to be surrendered, should a generator wish to opt-out of priority dispatch. Facilitating this will be important over the coming years as two increasingly large categories of renewable generators begin to emerge – i) out-of-support units who now rely solely on market revenues and ii) generators availing of new support schemes such as the Renewable Electricity Support Scheme (RESS). Both categories of generators are unlikely to want to be dispatched on the system during times of negative pricing, as negative prices will not be supported by any future RESS scheme as per the Directive. As negative prices are likely to be a ubiquitous feature of the Market it is imperative that non-dispatchable Units will be able to financially manage their position in the Balancing Market, avoiding imbalances costs during at times of negative pricing.

BnM is strongly of the view that development limitations to Central Market Systems should not be allowed to determine the direction, and rate of deployment of future policy. To meet our ambitions as set by the National Energy and Climate Plan, it is key that renewable generation, as an increasingly significant proportion of the generation market, be afforded full access to trade in the internal market by allowing them to submit Commercial and Technical Offer Data (COD and TOD) and participate on the price formation in the Balancing Market.

An important consideration around the submission of Commercial and Technical Offer Data (COD and TOD) is the accuracy of the Physical Notifications for renewable generators. Most Market Participants' forecasting methodologies are typically more accurate than the TSO. Also, the standard deviations for wind forecast are very significant so a tolerance level of +-5-10% would not work. For a Market Participant to be balance responsible it is key that it is given the right tools to manage its imbalance position. This requires the TSO respecting submitted Physical Notifications for balance purposes, when supplied by generators, without the potential modification/correction of the TSOs.

The consultation paper fails to grasp the real-world overheads associated with 'zero marginal cost'. Although, the variable costs for a non-controllable unit may be zero, there are significant capital costs that need to be repaid. Also, there is the concept of opportunity costs due to the loss of revenue to redispatch. The spirit of the Regulation, defines a fairer model which include options for remunerating opportunity costs by including these on the decremental bids and offers (-Refit Price-Balancing Payment).

It is BnM belief that by facilitating the access of non-priority dispatch units to become price makers in I-SEM would reduce the volume of dispatch down by aligning the ex-ante market schedule and the physically feasible dispatch.

BnM agree with the interpretation of Article 13(5) which requires that the System Operator(s) invest in network infrastructure (both transmission and distribution infrastructure) to minimise the redispatch of renewables and HE CHP. The requirements for such investment is only limited to the extent that system operators can demonstrate that any non-market redispatch is more efficient than additional network investment. This principle only makes sense if it is the case that renewable and HE CHP generators are compensated, as required under Article 13(7) for the impact of any net non-market based redispatch arising.

In parallel, system operators must take all reasonable measures, (subject to system security) to ensure non-market based redispatch is minimised. This in turn should mean a minimisation of compensation payable with associated benefits for the end consumer.

2.2 The cut-off date for projects to qualify for priority dispatch

On the options to grandfather rights to priority dispatch, BnM favour a clean break between REFIT and RESS, and as such consider the appropriate definition for contracts concluded prior to 4th July 2019 to be with reference to projects that had concluded the relevant contracts – i.e. REFIT Letter of Offer or PPA – providing a route to market.

2.3 Loss of priority dispatch due to 'significant modifications'

Article 12 envisages loss of priority dispatch where there is a significant modification to a power-generation facility. There is deemed to be a significant modification to a power-generation facility, where a new connection agreement "is required". The term "significant modification" needs careful consideration, as it may lead to adverse consequences, particularly where amended and revised connection agreements are issued to address, for example, a separately metered extension to allow for co-location of new renewables development with existing generation.

It is Bord na Mona's position that a new connection agreement by itself does not trigger the loss of priority dispatch; priority dispatch is lost if there a material change in the installed capacity of the power generation facility. BnM would support the development of a schema that clearly calls out the delineation between amendments which are significant and those that are deemed non-significant – as mentioned during the bilateral engagement, there are existing analogous processes, which could serve as a template for the RAs, already in place for EPA licences which distinguish between technical amendments and the need for a full review of EPA licences.

2.4 Proposed Revisions to the Priority Dispatch Hierarchy

As part of our Brown to Green Strategy BnM has positioned itself at the forefront of delivering on government policy and national decarbonisation commitments. As such BnM has made commitments to suspend peat harvesting operations and continuing the transition for Edenderry power station (EPL) to move EPL to 100% renewable sustainable biomass by1st of January 2024.

BnM supports the revision of the existing priority dispatch hierarchy, however we would welcome more clarity on the rationale for change as this is not a requirement of the Regulation.

One key point that we disagree on but believe to be a potential oversight is the exclusion of Hybrid plants from the proposed revised priority dispatch hierarchy. **Hybrid plants should be included within the same category as High Efficiency Cogeneration / Biomass / Waste to Energy.**

This is only a transitional stage as by Jan 2024 EPL will be operating as a Biomass plant only.

It is Bord na Mona's position that the new proposed priority dispatch hierarchy set out in Section 4.3 is in line with Article 13 (6) and (b).

3. Article 13

Bord na Mona fundamentally disagree with the position taken by the RAs in relation to their interpretation of Article 13(7).

Firstly, the differences in reasons for non-market based redispatch in I-SEM compared to other European markets do not justify the Regulatory authorities proposing to set aside the legal obligations arising from the Electricity Regulation to compensate for such redispatch. In addition, we understand that there was no request by the Governments party to the SEM to seek any derogation from any aspect of the Regulation.

This Article places obligations on System operators to minimise non-market based redispatch in the first instance, and only where non-economic to eliminate non-market based re-dispatch to compensate for the opportunity cost of such minimal level of redispatch. If there is no compensation payable by system operators, there is no incentive on them to minimise the levels of redispatch in the first instance.

The RAs argue unconvincingly that constraints are a form of market based re-dispatch, as it takes account of participants commercial and technical offer data to minimise the cost of diverging from physical notifications. However, this explanation cannot and does not include the case where generators are constrained due to local network constraints, which is a form of redispatch without regard to market physical notifications or commercial offer data. There is no reasonable basis that this type of redispatch can be classified as market based. Therefore**, the constraint of generators for network congestion reasons can only be classified as non-market redispatch**, and consequently should be fully compensated up to the value of the unit's financial support.

Furthermore, compensation for constraints is currently remunerated in the Balancing Market for Generators with a firm connection offer only through the introduction of the discount payment. However, if the Generator in question is in receipt of financial support through the PSO these payments are netted off. Therefore, the result is that there is no actual compensation to such generators for constraints. Also, the compensation is limited only to Energy Prices and does not consider additional financial support payments, which are entitled under the current regulation.

The RAs differentiate the concept of compensation for non-firm compared to projects with physically firm in their discussion and analysis. The concept of firmness of access has historically and consistently related to financial compensation solely in the context of constraint related redispatch. BnM believe it is entirely unreasonable and contrary to all previous regulatory decisions that the treatment of compensation for redispatch due to curtailment be differentiated according to the state of firmness of a generators grid connection. For clarity, Bord na Mona believe that where a renewable or HE CHP is subject to curtailment, that compensation in accordance with Article 13(7) is due in all cases, and that compensation is due in the case of constraint, where a generator has a level of firm access associated with their grid connection agreement.

Bord na Móna does not see any opportunity in the Regulation to determine whether compensation is unjustifiably high when calculated from the viewpoint of the totality of consumers – the drafting (and legislative history) of the regulation clearly seeks to compensate generators, who through no fault of their own, have been Redispatched by the SO and have subsequently suffered an economic disadvantage. The regulation is quite specific in determining the level of compensation that is required to be paid to generators who are redispatched. The only course of action which is legally open to the RAs is to direct the System Operators to pay the specific levels of compensation that has been set out in the regulation, in the case of non – market re-dispatch to renewable and HE – CHP generators. This should be applied retrospectively to such generators from when the Regulation came into force, on 1st January 2020.

With respect to the costs associated with such compensation, the RAs are not considering the impact that granting compensation as required under the regulation would have on future competitive auction processes for renewable electricity supports. The impact of uncompensated curtailment is a factor that a rational developer would have to take account of in preparing an estimate of the support price required for a project bidding into a competitive auction process. Where this uncertainty is removed, it will deliver a direct benefit to consumers which can offset the impact of any compensation costs arising from non-market based dispatch of renewable generators that cannot be eliminated through network investment and other system measures by the system operators

There is a moral hazard of setting aside the obligations of this regulation, which may fundamentally limit the ability of I-SEM to deliver the levels of renewable penetration envisaged in Government and EU policy. The effect of reflecting the actual compensation costs for non-market based redispatch which cannot be eliminated, should give market signals to other forms of market balancing, including demand side markets, interconnector investment and modal shifts into other energy markets in due course, (such as power to gas). If these costs are not explicitly defined and compensated, it may limit or delay the development of alternative market based solutions which can alleviate re-dispatch, and thereby limit or delay the achievement of the significant potential for renewable electricity penetration in this market.

4. Responses to Questions issued as part of the consultation

Consultation Question 1:

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.*

As mention in section 2.2 of this response BnM's preferred approach is a clean break between REFIT and RESS, and as such consider the appropriate definition for contracts concluded prior to 4th July 2019 to be with reference to projects that had concluded the relevant contracts – i.e. REFIT Letter of Offer or PPA – providing a route to market.

Consultation Question 2:

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.

This coincides with our current understanding. It is our belief that for new dispatchable units I-SEM complies with the implementation of Article 12 of the new Electricity regulation.

Consultation Question 3:

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 mention in the body of the response, BnM is strongly of the view that renewable generation, as an increasingly significant proportion of the generation market, be afforded full access to trade in the internal market by allowing them to submit Commercial and Technical Offer Data (COD and TOD) and participate on the price formation in the Balancing Market.

Another point to consider, is around the accuracy of the Physical Notifications for renewable generators. Most Market Participants forecasting methodologies are more accurate than the TSO. Also, the standard deviations for wind forecast are very significant so a tolerance level of +-5-10% would not work. For a Market Participant to be balance responsible it is key that it is given the right tools to manage its imbalance position. This requires market participants having the option to use its own Physical Notifications for balance purposes without the potential modification/correction of the TSOs.

It is BnM belief that by facilitating the access of non-priority dispatch units to become price makers in I-SEM would reduce the volume of dispatch down by aligning the ex-ante market schedule and the physically feasible dispatch.

Consultation Question 4:

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

It is BnM's view that for non-market and non-controllable generators no change is needed for these generators whether they are market participants or not.

For controllable non-market generators, a solution is needed which aligns with Article 13.7 requirements.

Consultation Question 5:

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?

This is consistent with Article 12.1 which states that the dispatching of power generation facilities and demand response shall be non-discriminatory, transparent and market based. As already mentioned on our response to Question 3 of this consultation, that renewable generation be afforded full access to trade in the internal market by allowing them to submit (if so desired) Commercial and Technical Offer Data (COD and TOD) that are respected by the TSO and participate on the price formation in the Balancing Market.

Consultation Question 6:

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

Although, the variable costs for a non-controllable unit might be zero there are significant capital costs that need to be repaid. Also, there is the concept of opportunity costs due to the loss of revenue from redispatch, a fairer and more market reflective model will remunerate these opportunity costs by including these on the decremental bids and offers.

Consultation Question 7:

What is your view on a potential ruleset 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?

It is our recommendation that the rules for bid-offer acceptance classification requires further review, consultation and impact assessment against different classes of generator, and ultimately appropriate governance of the rules.

Consultation Question 8:

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.

As mentioned on the body of the response section 2.4,

BnM supports the revision of the existing priority dispatch hierarchy, however we would welcome more clarity on the rationale for change as this is not a requirement of the regulation.

One key point that we disagree on but believe to be a potential oversight is the exclusion of Hybrid plants from the proposed revised priority dispatch hierarchy. **Hybrid plants should be included within the same category as High Efficiency Cogeneration / Biomass / Waste to Energy.**

This is only a transitional stage as by 2024 EPL will be operating as a Biomass plant only.

It is Bord na Mon's position that the new proposed priority dispatch hierarchy set out in Section 4.3 is in line with Article 13 (6) and (b).

Consultation Question 9:

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.

No additional feedback provided at this stage.

Consultation Question 10:

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.

One of the key goals of the Electricity Regulation is to promote a non-discriminatory, transparent, market-based electricity-based dispatching of power generation facilities. It also suggests for Member States to provide incentives for priority dispatch units to voluntarily give up priority dispatch.

BnM's sees priority dispatch as a right rather than an obligation and are fully supportive to facilitate a mechanism for units in receipt of priority dispatch to be able to opt out if they decide to do so.

Consultation Question 11:

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.

Yes, BnM agree with the interpretation of Article 13(5) requires that the System Operator(s) invest in network infrastructure (both transmission and distribution infrastructure) to minimise the re-dispatch of renewables and HE CHP. The requirements for such investment is only limited to the extent that system operators can demonstrate that any non-market re-dispatch is more efficient than additional network investment. This principle only makes sense if renewable and HE CHP generators are compensated, as required under Article 13(7) for the impact of any net non-market-based re-dispatch arising.

In parallel, system operators must take all reasonable measures, (subject to system security) to ensure non-market-based re-dispatch is minimised. This in turn should mean a minimisation of compensation payable with associated benefits for the end consumer.

The differentiation in priority between RE generators and HE CHP generators are covered in Article 13 (6) (a) & (b). This indicated that non-market based re-dispatch of HE CHP generators by system operators should occur before non-market based re-dispatch of renewable generation, and only where no other alternative exists which would not lead to a severe risk to network security, or a significantly disproportionate cost to the system.

Consultation Question 11b:

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?

BnM agree with the interpretation of Article 13(6) outlined in the consultation paper Section 4.3 in relation to the hierarchy for non-market-based re-dispatch.

Consultation Question 12:

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?

Firstly, the differences in reasons for non-market-based re-dispatch in I-SEM compared to other European markets do not justify the Regulatory authorities proposing to set aside the legal obligations arising from the Electricity Regulation to compensate for such re-dispatch.

This article places obligations on System operators to minimise non-market-based re-dispatch in the first instance, and only where non-economic to eliminate nonmarket based re-dispatch to compensate for the opportunity cost of such minimal level of redispatch. If there is no compensation payable by system operators, there is no incentive on them to minimise the levels of re-dispatch in the first instance.

The RAs conclude the constraints are a form of market-based re-dispatch, as it takes account of participants commercial and technical offer data to minimise the cost of diverging from physical notifications. This explanation cannot include the case where generators are constrained due to local network constraints, which is re-dispatch without regard to market physical notifications or commercial data. There is no reasonable basis that this type of re-dispatch can be classified as market based. Therefore, the constraint of generators for network congestion reasons should be classified as non-market redispatch, and consequently entitled to compensation where it arises for renewable and HE CHP generators.

The RAs differentiate the concept of compensation for non-firm compared to projects with physically firm in their discussion and analysis. The concept of firmness of access has historically and consistently related to financial compensation solely in the context of constraint related re-dispatch. BnM believe it is entirely unreasonable and contrary to all previous regulatory decisions that the treatment of compensation for re-dispatch due to curtailment be differentiated according to the state of firmness of a generators grid connection. For clarity, Bord na Mona believe that where a renewable or HE CHP is subject to curtailment, that compensation in accordance with Article 13(7) is due in all cases, and that compensation is due in the case of constraint, where a generator has a level of firm access associated with their grid connection agreement.

Bord na Mona do not concur with the interpretation of the RAs that the level of compensation arising under Article 13 can be adjusted if deemed unjustifiably high, in terms of the cost to the totality of consumers. The regulation is quite specific in determining the level of compensation that is required to remunerate generators who have been redispatched through no fault of their own, and includes provisions to ensure that the compensation paid is neither higher nor lower than that intended in the regulation.

With respect to the costs associated with such compensation, the RAs are not considering the impact that granting compensation as required under the regulation would have on future competitive auction processes for renewable electricity supports. The impact of uncompensated curtailment is a factor that a rational developer would have to take account of in preparing an estimate of the support price required for a project bidding into a competitive auction process. Where this uncertainty is removed, it will deliver a direct benefit to consumers which can offset the impact of any compensation costs arising from non-market based dispatch of renewable generators that cannot be eliminated through network investment and other system measures by the system operators

There is a moral hazard of setting aside the obligations of this regulation, which may fundamentally limit the ability of I-SEM to deliver the levels of renewable penetration envisaged in Government and EU policy. The effect of reflecting the actual compensation costs for non-market based redispatch which cannot be eliminated, should give market signals to other forms of market balancing, including demand side markets, interconnector investment and modal shifts into other energy markets in due course, (such as power to gas). If these costs are not explicitly defined and compensated, it may limit or delay the development of alternative market based solutions which can alleviate re-dispatch, and thereby limit or delay the achievement of the significant potential for renewable electricity penetration in this market.

Consultation Question 12b:

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?

As we have previously stated in the response to question 12 above, Bord na Mona does not believe that the RAs have the discretion or legal basis to alter the compensation payable as clearly defined in the Regulation. The only course of action which is legally open to the RAs is to direct the System Operators to pay the specific levels of compensation that has been set out in the regulation, in the case of non – market re-dispatch to renewable and HE – CHP generators. This should be applied retrospectively to such generators from when the Regulation came into force, on 1st January 2020.

If you have any queries or require clarification on any point, please do not hesitate to contact me.

For and on behalf of Bord na Móna,

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