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IWEA Position Paper on Priority Dispatch and Compensation for Constraint and Curtailment, arising from EU Regulation 2019/943

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Executive Summary

Context

Renewable generation in the Single Electricity Market (SEM) has benefitted to date from priority of dispatch. Priority of dispatch is where a generator is let generate to meet demand without having to compete commercially with other generators. However, there will be times when it is not possible to accommodate all priority dispatch generation while maintaining the safe, secure operation of the power system. Security-based limits must be imposed due to both local network and system-wide security issues. It is, therefore, necessary to reduce the output of renewable generators below their maximum available level when these security limits are reached. This reduction is referred to as 'dispatch-down' of renewable generation. The dispatch down of renewable generation in the SEM, and the compensation it is entitled to is set out in SEM-11-062 (and subsequent clarifying decisions).

These rules for the dispatch down of renewable generation and their compensation now need to be re-evaluated due to new regulations from Europe, specifically the new Electricity Regulation EU/2019/943 under the Clean Energy Package. The relevant Articles in the Regulation come into effect on 1st January 2020.

The Irish Wind Energy Association ("IWEA") has evaluated the Regulation, and have arrived at a solution for the treatment of renewable generation which meets the following criteria:

(a) Compliance with the Regulation;
(b) Historic investment in renewable energy projects is not undermined;
(c) Cost effective participation in the upcoming Renewable Electricity Support Scheme ("RESS") auctions;
(d) Structural certainty provided to support the development of Corporate PPAs in line with Government policy; and
(e) Quick and easy to implement.

This paper focusses on IWEA's position, which has been informed in part with correspondence from DG ENER (via Wind Europe).

For the avoidance of doubt, IWEA is also willing to discuss alternative approaches which meet the above criteria.

IWEA's Position on Implementation of New Regulation

The following key principles, and resulting consequences, set out IWEA's position on the new Regulation's Impact on renewable generation in the SEM.

- Article 12 of the Regulation clearly states that most new renewable generators are no longer entitled to Priority Dispatch, while established renewable generators continue to benefit from Priority Dispatch;
  - Very small renewable generation projects continue to benefit from Priority Dispatch;
  - The Regulation allows projects which are actively progressing towards financing and commissioning on the 4th of July to also benefit from Priority Dispatch once operational. IWEA views that generators that can demonstrate a financeable route to market (e.g. REFIT Letter of Offer, corporate power purchase agreement) before the 4th of July, and become operational on that basis, meet that allowed exception;
- This loss of Priority Dispatch means that new renewables have to compete to provide energy balancing services[1], whereas established renewable generators continue to be scheduled to produce irrespective of price;
- However, Article 13 of the Regulation sets out that all "non-market redispatch" treats all renewables equally, irrespective of whether they benefit from Priority Dispatch. This clarification that Priority Dispatch should not be considered in non-market redispatch was provided by DG ENER;
- Constraint[2] and Curtailment[3] meet the definition of "non-market redispatch" in the Regulation;
- Therefore, despite new renewable generators losing Priority Dispatch, **new non-priority dispatch renewable generators are treated identically to, or pro-rata in dispatch with, legacy Priority Dispatch renewable generators for the purposes of constraint and curtailment.**
- Article 13 of the Regulation also sets out that **generators should be compensated, including at the level of any financial support,** unless they have accepted a connection offer with no guarantee of the firm delivery of power;
  - Financial support includes renewable subsidy;
  - Consistent with IWEA's previous position in this matter, IWEA is of the view that firmness of a grid connection is not relevant for curtailment, only constraint, and as such both firm and non-firm generation should be compensated under Article 13 for curtailment. IWEA argues that in the context of renewable subsidy auctions, this is better for the consumer and for competition; and
- **New renewable generators without Priority Dispatch are disadvantaged relative to legacy Priority Dispatch generation only in relation to energy balancing**.

[1] Energy balancing, or dispatch, is the process where generators are scheduled and dispatched to meet the energy demand requirement, prior to consideration of system security issues. This includes the dispatch down of wind where there is more generation scheduled in ex ante trading than is required to meet demand.

[2] Constraint refers to the dispatch-down of generation for more localised network reasons (where only a subset of generators can contribute to alleviating the problem).

[3] Curtailment refers to the dispatch-down of non-synchronous renewables for system-wide reasons (where the reduction of any or all wind generators would alleviate the problem).

A visualisation of the classification of curtailment, constraint and energy balancing for excess generation is provided in Figure 1.

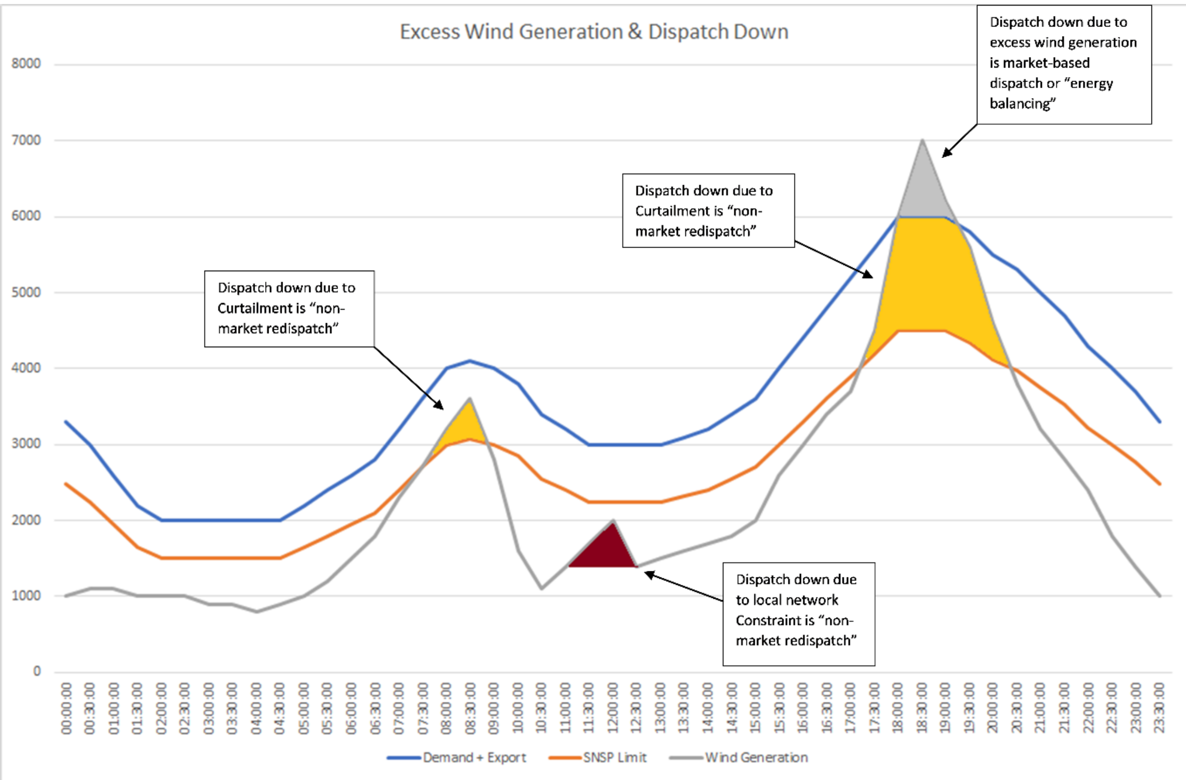

Figure 1: Visualisation of curtailment, constraint and energy balancing events over a trading day in the SEM

Review of New Regulation's Impact on Renewable Generation in SEM

The resulting impact of the Electricity Regulation on new renewable generation and legacy renewable generation with Priority Dispatch was modelled by MullanGrid and is presented in Figure 2.

Figure 2 examines the level of "dispatch down" for New Wind and Priority Dispatch Wind excluding constraint. "Dispatch down" includes both energy balancing (for which new wind does not have Priority Dispatch) and subsequent curtailment (which all renewables share pro-rata after any energy balancing has occurred). Note that that any such forecast analysis is based on a series of assumptions, such as the impact of negative market prices on market participant's behaviours including the potential for older generators voluntarily waiving the benefit of priority dispatch, the potential for repowering sites, the export behaviour of new interconnection, and other such considerations.

In this analysis, dispatch down is maintained pro-rata for all renewable generation and, and all renewables experience dispatch down in the order of 4% in 2020 falling to 3.5% in 2024. However, from 2025 onwards, with the introduction of substantial further delivery in renewable generation, the positions diverge. The new non-priority dispatch renewables must compete like all other generation for energy balancing which results in being turned off during excessive generation events[4] and thus increasing the level of dispatch down. Such dispatch down is in line with projections of overall supply and demand in the market and where the generator has a firm connection offer, can be compensated through standard market mechanisms. The impact of assumptions regarding non-synchronous curtailment remains averaged across the entire wind portfolio and remains at a relatively consistent level throughout the decade.

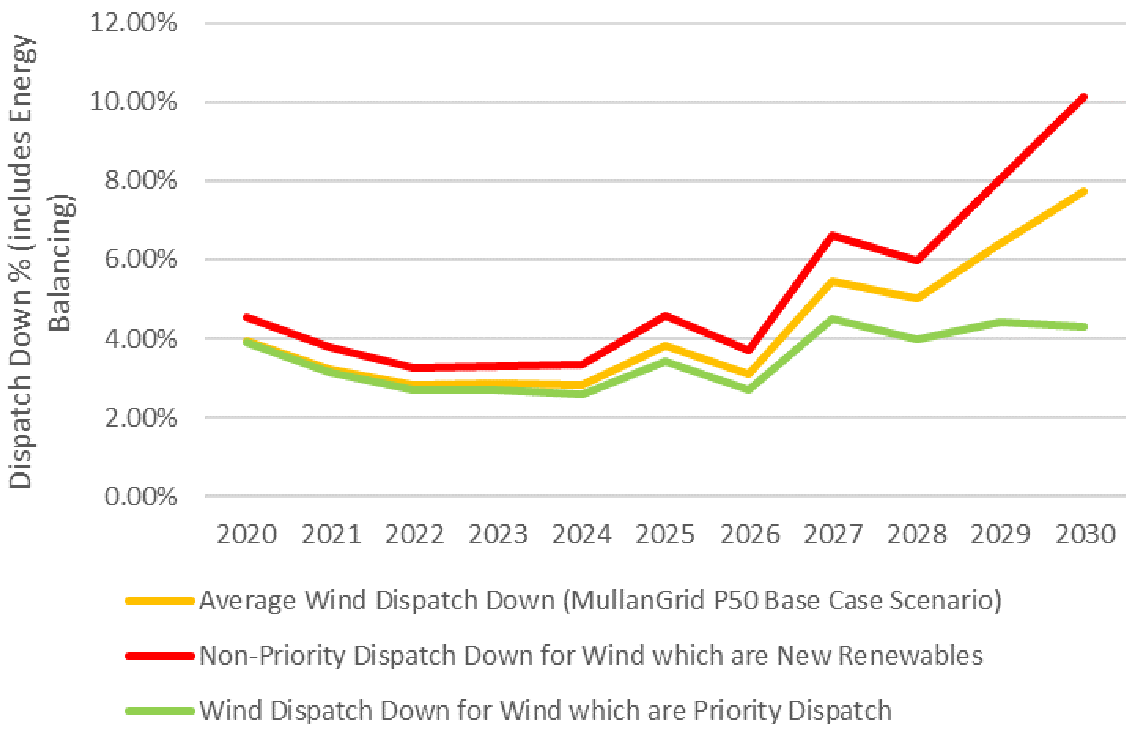

Figure 2: Implications of Regulation on Dispatch Down for New Wind and Priority Dispatch Wind (excludes constraints)

While this still leads to a more challenging investment environment for new renewables, it is a much more predictable outcome than having all new renewables face the marginal impact of constraint and curtailment, where dispatch down in excess of 20% by 2020 has been modelled for new renewables.

IWEA's preferred policy position is that dispatch down could have remained pro-rataed for all circumstances including energy balancing, provided the correct levels of compensation could be

[4] Where renewable generation exceeds total demand to be serviced, including interconnector exports. These concepts are covered again with a simple numerical example in the Introduction's definition subsection and are shown in Figure 1.

allocated to the existing portfolio. However, having worked through multiple alternatives and being unable to come to this position, this described position is our preference for the best outcome given the constraints of the Electricity Regulation. Should an alternative suggestion be put forward by another party which achieves the initially desired outcome, IWEA would be willing to discuss this in greater detail.

Benefits of IWEA's Position

The following benefits arise:

- In an environment where new renewables have no priority dispatch and must compete with priority dispatch legacy renewables, this provides the greatest certainty and therefore the lowest Renewable Electricity Support Scheme (RESS) offers, benefitting consumers;
- The greater predictability of future output for new generators de-risks renewable power delivery for corporate PPAs;
- Legacy priority dispatch generators' historic investments are not undermined;
- With appropriate energy bidding and resulting scheduling by the TSO, dispatch will remain largely pro-rata for the foreseeable future.

Other Considerations and Next Steps

This Position Paper goes into considerable further detail across a range of related issues.

- The implications for SEM's priority dispatch hierarchy amongst different classes of renewables and High Efficiency (HE) CHP;
- The importance of firmness for connection offers (being tied to compensation for energy and non-market redispatch for constraint);
- Interactions with renewable subsidies to ensure the Regulation's requirements for compensation are not undermined;
- The precise definition of what constitutes "new" renewables which is not entitled to Priority Dispatch;
- The treatment of below de minimis generation;
- Implications when there is a material change to a connection agreement such as hybrid facilities, repowering, and extensions.

While new renewables without Priority Dispatch are not envisaged in the very immediate future, participation in RESS auctions and the development of the CPPA market will require rapid implementation of the Regulation to create clarity for decision-makers. Connection policy consultations will interact with this Regulation with regard to firmness.

IWEA welcomes engagement with the Regulatory Authorities and the System Operators on the timely agreement of the interpretation of the Regulation. Longer-term, IWEA notes that to achieve renewable energy and decarbonisation targets, new paradigms of investment along with supporting demand response (including electricity storage, electrification of heat and transport, hydrogen production, interconnector development) will be required to reduce all forms of dispatch down but particularly during times of excess generation events.

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1. Introduction

The Irish Wind Energy Association ("IWEA") is the representative body of the Irish wind energy industry with over 150 members and welcomes the opportunity to present this position paper on Priority Dispatch and Compensation for Constraint[5] and Curtailment[6] [7] arising from EU Regulation 2019/943.

The Clean Energy Package comprises a suite of European Directives and Regulations which together update the EU's energy policy framework to assist in the transition away from fossil fuels and rationalises the common market rules for electricity markets.

The Electricity Regulation EU/2019/943 ("the Regulation") impacts a former key element of European Renewables Policy, namely it changes the Priority Dispatch of renewables on the Grid. It brings new requirements regarding the treatment of renewable generation's energy in physical dispatch, remuneration of all generation when dispatched away from their traded positions, and new concepts of "non-market redispatch" which require a home in the Single Electricity Market design. The Articles in Regulation EU/2019/943 which are discussed in this Position Paper come into effect on 1st January 2020.

Article 12 sets out requirements in Dispatching of Generation and Demand Response while Article 13 sets out redispatching[8] requirements. Specifically:

- Article 12 states that all generation dispatch shall be non-discriminatory, transparent and market based, with limited exceptions, including for legacy priority dispatch generation. This means that new renewable generation will be subject to price-based market dispatch, while old generation can continue to benefit from regulated priority dispatch;
- Article 13 states that all generation which are subject to redispatch – noting specifically that redispatch includes curtailment – shall be compensated, subject to various terms and conditions. This is new legal requirement differs to the existing policy in SEM of non-compensation for curtailment for within tie-break renewable generators, and the treatment of non-participant controllable windfarms which have no compensation mechanisms in place; and

[5] Constraint refers to the dispatch-down of wind generation for more localised network reasons (where only a subset of wind generators can contribute to alleviating the problem).
[6] Curtailment refers to the dispatch-down of wind for system-wide reasons (where the reduction of any or all wind generators would alleviate the problem).
[7] The SEM Committee approved in SEM-13-011 the difference between constraint and curtailment.
[8] The term redispatching is defined in the Regulation and effectively means a measure activated by one or several system operators by altering the generation and/or load pattern to change physical flows in the transmission system and relieve physical congestion.

- Article 13 also includes new hierarchies of “non-market redispatch”, encompassing renewables and High Efficiency Combined Heat & Power (HE CHP), irrespective of their Priority Dispatch status.

1.1 Regulation Terminology and this Position Paper’s Interpretation

Regulation EU/2019/943 introduces several concepts which are important to highlight and relate to more regular Single Electricity Market terminology where appropriate. For the avoidance of doubt, these are IWEA’s own explanation of how these terms relate to SEM terminology and are not meant to recast or limit the specific definitions provided in the Regulation.

“**Dispatch**” relates to the scheduling and dispatch of generation and demand response to meet the energy requirements of the market. This is analogous to final physical notifications (FPN) of generation (submitted by the generator or calculated by the TSO) which are subject to subsequent energy actions in the Single Electricity Market (SEM) design.

“**Redispatch**” relates to the adjustment of that energy balanced dispatched schedule to account for constraints, reserve requirements, curtailment, and general electrical system stability requirements. This is analogous to the concept of non-energy actions in the SEM design.

“**Market-based**” means the free competition of generation in a market mechanism to compete for dispatch and redispatch. The clear examples of such market-based dispatch and redispatch in the SEM design are the trading in the ex-ante markets and submission of FPNs and the actions taken by the TSO in the balancing market related to Incremental (INC) and Decremental (DEC) offers.

“Non-Market based” is where the free competition of generation does not apply. This could be either where a generator does not have a structure to offer a price (for example, below de minimis generation), but crucially also applies to situations where the free “market-based” competition has been regulated to avoid strategic bidding.

As such, there can be market-based redispatch, for example changing generators’ dispatches based on their competitive merit order to meet a system wide reserve requirement, and non-market based redispatch. It is a central element of the SEM design that constraint and curtailment in tie-break – due to its highly regulated non-competitive nature in the market – is a form of non-market based redispatch. For the avoidance of doubt, just because the balancing market has implicit DEC offers from windfarms, does not make redispatch due to curtailment market-based.

"**Dispatch Down**" is term used within this Position Paper to describe the instructed reduction in output from new renewables. It includes energy balancing, constraint and curtailment for these windfarms.

"**Energy balancing**" is a dispatch action taken by the TSO to ensure the energy balance of the system.

"Excessive Generation Event" is where available scheduled generators exceed the total demand (and interconnector exports) to be served.

"**Curtailment**" and "**Constraint**" are defined in footnotes above.

Appendix 2 includes a numerical example of the above concepts.

2. Objectives

IWEA has the following objectives for the implementation of the Regulation. The solution must:

- At a minimum be compliant with the Regulation and is legally robust;
- Not negatively impact existing windfarms that are currently benefitting from priority dispatch;
- Continue to facilitate efficient development of renewable energy generation within the context of corporate power purchase agreements (CPPAs) and under the new Renewable Electricity Support Scheme (RESS); and
- Be quickly and easily implementable.

IWEA recognises that certain increased costs and responsibilities for new windfarms relative to legacy priority dispatch windfarms may be unavoidable. “Efficient” development in the third bullet point above is not meant to reflect an absolution from said costs or responsibilities, but rather that these costs and responsibilities can be modelled with reasonable certainty during a project’s development and can therefore be financed efficiently at the start of commercial operation. This gives developers and financiers the appropriate levels of certainty to continue towards the fulfilment of Ireland’s renewable target ambitions.

3. Regulation in Relation to Priority Dispatch: Article 12

Article 12 deals with how all dispatchable resources (demand, generators) shall be dispatched on a transparent market basis, and spends most time dealing with how priority dispatch will continue to be managed.

Paragraph 1 states that all generation shall be subject to transparent, non-discriminatory market-based dispatching except under certain specific exceptions.

Paragraphs 2 through 5 deal primarily with the granting of priority dispatch for small renewable and HE CHP generators. This is outside the scope of this note at this time. However, it is noted that paragraph 3 says that Member States may provide incentives for installations eligible for priority dispatch to voluntarily give up priority dispatch.

Priority dispatch entails the System Operator dispatching the system using criteria different from the economic order of bids. For the avoidance of doubt, it is IWEA's position that the "absolute" interpretation of Priority Dispatch as set out in SEM-11-062 shall be maintained, i.e. that Priority Dispatch generation shall have full priority for delivery of physical power, subject only to security and safety concerns and interconnector flows. IWEA's position is consistent with paragraph 7 of the Regulation.

Paragraph 6 provides important legacy protections to generation facilities who were commissioned or had contracts signed[9] prior to the 4th July 2019 and had priority dispatch under the previous directives dealing with the granting of priority dispatch to renewable and HE CHP generation.

Finally, in paragraph 6, legacy generation which is subject to material modification (being at least where a new connection agreement is required or where the generation capacity of the generator is increased) shall no longer be entitled to priority dispatch.

Paragraphs 2 through 6 therefore will have an impact on current SEM policy.

[9] IWEA has interpreted that signed contracts refers to a project which can demonstrate a financeable route to market (e.g. REFIT Letter of Offer, corporate power purchase agreement) before the 4th of July, and become operational on that basis, as set out in Section 6 of this paper.

4. Regulation in Relation to Redispatching: Article 13

Article 13 deals with redispatching. Redispatching is clearly defined in the Regulation and as such is solely for maintaining the technical secure operation of the electrical system, and includes such actions to ensure the energy comes from appropriate sources, for example to deal with curtailment and power line capacity limitations. In SEM terminology, redispatching may be considered "Non-Energy Actions".

Paragraph 1 states that all facilities that are capable of providing a redispatching service – including those from other member states – shall be allowed to do so based on objective, transparent and non-discriminatory criteria.

Paragraph 2 states that all resources that are redispatched using market-based mechanisms shall be compensated. The paragraph does not go into a definition of "market-based", nor does it specify whether those generators should have a firm connection offer (as is specified later in the Article).

Paragraph 3 deals with the scenarios where non-market based redispatching may be used. Non-market based downward redispatching utilises a different dispatch hierarchy than a commercial merit order; understanding what is market-based or non-market-based redispatch is therefore highly important for the treatment of constraint and curtailment for windfarms. The four scenarios set out in paragraph 3 are following, one of which applies:

"(a) no market-based alternative is available;

(b) all available market-based resources have been used;

(c) the number of available power generating, energy storage or demand response facilities is too low to ensure effective competition in the area where suitable facilities for the provision of the service are located; or

(d) the current grid situation leads to congestion in such a regular and predictable way that market-based redispatching would lead to regular strategic bidding which would increase the level of internal congestion and the Member State concerned either has adopted an action plan to address this congestion or ensures that minimum available capacity for cross-zonal trade is in accordance with Article 16(8)."

Paragraph 4 deals with reporting requirements for the TSO and CRU around the levels of, procurement of, and effectiveness of redispatching, with particular reference to the redispatching of renewables and HE CHP.

Paragraph 5 requires, subject to reliability and safety of the electrical system, to minimise the necessary downward redispatching of renewable and HE CHP facilities, and sets a limit of 5% of downward redispatch of renewables and HE CHP (subject to grids where renewables and HE CHP deliver less than 50% gross final consumption of electricity, whereby Member States may choose to forego that requirement).

Paragraph 6 states where downward redispatching of generation is required on a non-market basis (as per paragraph 3) a particular hierarchy should be used. It is noteworthy that this redispatching makes no distinction as to whether renewables or HE CHP have or have not priority dispatch within this hierarchy.

Before any non-market redispatch, all market-based conventional generation should have been subjected to market-based redispatch. It is noted that this includes redispatch of resources available in other Member States, which IWEA interprets as an obligation for the TSO to avail of market-based balancing in neighbouring markets to produce counter-flow on interconnection. Then, the classes of generators below are turned down in the following order:

- First, HE CHP generation (without reference to priority dispatch); followed by
- Renewable energy (without reference to priority dispatch); followed by
- Self-consumed renewable or HE CHP power which is not exported to the grid.

Paragraph 7 sets out that non-market redispatching should be compensated at the higher of the increased costs arising from redispatching (examples given here relate to HE CHP), or the day-ahead market energy sales foregone including any financial support that the redispatched source would have otherwise received. Such compensation is subject to having not “accepted a connection agreement under which there is no guarantee of firm delivery of energy”. A blend of the incurred costs or foregone revenues may be used where this results in unjustifiably low or high compensation.

It is clear that following an agreed definition of non-market redispatch, there are many provisions in Article 13 which may have a material impact on the operation of Single Electricity Market policy. There are also potential implications (depending on the nature of the compensation envisaged within Article 13 of the Regulation) on the Balancing Market Principles Code of Practice / Bidding Code of Practice and non-firm connection policy in the Single Electricity Market.

5. Non-Market Redispatch in SEM Defined

It is IWEA's position that all constraint and curtailment are non-market redispatch. SEM-11-062 (and subsequent decisions SEM-11-105, SEM-13-010 and SEM-13-012) represent a series of decisions by both regulators which recognise that standard market settlement and treatment of renewables in dispatch would lead to material, predictable issues in the successful operation of the market. The potential for different low-marginal cost renewable generators (some subsidised under a feed-in-tariff, some merchant, some in receipt of a renewable certificate) competing on price or on other characteristics to achieve a preferential dispatch in the merit order during predictable curtailment events (events in which only those renewables could compete) would result in a race to the lowest price possible, distorting efficient market prices. The resulting series of rules around priority dispatch hierarchy in constraint and curtailment based on issues such as technology type, firmness of connection, and other considerations, are by definition not market-based actions taken by the System Operator. Correspondingly, constraint and curtailment of renewables (and by extension HE CHP) in the SEM has already been assessed by the Regulatory Authorities to fall under Article 13, paragraph 3(d).

6. Resulting Dispatch and Compensation Consequences

6.1. Pro-Rata for Constraint and Curtailment for New and Old Renewable Generation

As constraint and curtailment are non-market redispatch, all renewables are dispatched down together for the management of constraint and curtailment as per Article 13 paragraph 6. This applies to both legacy priority dispatch plant (as per Article 12, paragraph 6) and all other renewables.

6.2. SEM Priority Dispatch Hierarchy Needs to Change

Article 13, paragraph 6 sets out a new hierarchy for the management of renewables and HE CHP during constraint and curtailment events. This is different to the existing SEM hierarchy under SEM-11-062. This needs to be considered and the full set of rules in the hierarchy need to be re-evaluated, including whether the treatment of minimum generation for other renewables is supported by the Regulation.

6.3. Legacy Priority Dispatch Generation Maintains Priority for Energy Actions

Dispatch for energy reasons, i.e. balancing the energy market or in extremis an excessive generation event, requires the TSO to balance scheduled generation (and demand response) to the required level of demand. These energy actions for "new renewables" commissioned post July 4th, 2019 (see clarification below) are treated on a commercial merit order basis with all other classes of generation. Existing Priority Dispatch generation will continue to benefit from the absolute interpretation of priority dispatch set out in SEM-11-062.

6.4. Compensation for Renewable Constraint / Curtailment (Non-Market Redispatch)

As per Article 13, paragraph 7, if the generators subject to non-market redispatch have not *"accepted a connection agreement under which there is no guarantee of firm delivery of energy"*, they are due compensation at the higher of the extra costs incurred, the day-ahead trade that would have otherwise been possible including any financial support foregone. This requires changes to the settlement of generators today, either under the Trading & Settlement Code or via another mechanism. Please see the comment below on compensation for curtailment for non-firm generation below. Please also see the comments in relation to the interaction with the Renewable Energy Feed in Tariff (REFIT) discussed in the next Section.

6.5. Treatment of Below De Minimis Generation

There is nothing in the Regulation which allows below de minimis generation to be treated any differently to market participants. Correspondingly, below de minimis generation which can be controlled by the TSO, and are controlled by the TSO for the same non-market reasons as market participants should:

- Be treated identically for constraint and curtailment as larger generation, as happens today; and
- Should be subject to compensation at any equivalent rate (if not necessarily through an equivalent process or funding mechanism) as large generation. This latter point is a material change to the treatment of controllable out-of-market generation.

6.6. Treatment of Non-Market Redispatch and Non-Firm Generation

IWEA has consistently drawn attention to the fact that wind curtailment (due to system non-synchronous penetration limitations) is not related to the firmness of a grid connection. Correspondingly, it remains IWEA's position that no generator has ever accepted a connection offer that does not guarantee delivery of power for reasons of curtailment.

It follows therefore from the Regulation that both firm and non-firm windfarms should receive compensation for curtailment. It is noted that Article 13, paragraph 7 only requires firm generation to be compensated, but it is within the gift of Member States to compensate non-firm generators if appropriate to do so.

The Regulatory Authorities should only take discretionary action where it better fulfils their legal requirements. IWEA notes that:

- Compensation for non-firm curtailment is <u>better for consumers</u> within the context of auction-based renewable subsidies, such as RESS. Consumers will have to pay for curtailment whether new generators are compensated through the market or not. For example, if not compensated for non-firm curtailment, a developer needs to assess the risk of the level of curtailment and forecast when the connection agreement might become firm. These assumptions will necessarily have to be conservative to meet financing requirements, and will therefore inefficiently raise the offer price in RESS. However, if compensated for curtailment, the pricing of risk could be stripped out of the RESS auction offer, leading to a net saving to the consumer where only the actual compensation is paid through the market.
- Compensation for non-firm curtailment is <u>better for competition</u> in the context of the RESS auction. Where RESS auction competitors have to forecast firmness as part of their auction offer, or there are firm and non-firm generator's competing within the auction, firmness – which to repeat has nothing to do with the ability of a generator to deliver during periods of curtailment – becomes a distorting factor in the auction outcomes. More expensive firm

generators may be successful in the auction (and lock those prices in for periods greater than any reasonable projection of the duration of their competitors' non-firmness) than the potential offers from non-firm generators.

6.7. Treatment of Generation Built Shortly after July 4th 2019

The non-applicability of priority dispatch to generators commissioned post July 4th 2019 is "*Without prejudice to contracts concluded before 4 July 2019*". It is IWEA's position that the *"Without prejudice"* seeks to achieve protection for active projects with a clear route to market that are actively making progress on financing and commissioning. The most objective measure of this is a windfarm that can demonstrable evidence of a route to market, such as a REFIT Letter of Offer or a CPPA before 4th July 2019. The generator developers have made material investment in the expectation of certain market and/or subsidy interactions for such projects, and correspondingly such generation once constructed and operational should continue to benefit from full priority dispatch. For the avoidance of doubt, the generator would not qualify for priority dispatch should it become commercially operational under a different route to market, e.g. progressed with RESS in place of REFIT, other than one of those demonstrated by the applicable deadline.

6.8. Incentivisation to Forego Priority Dispatch

The Regulation allows incentivisation for all generators with Priority Dispatch to voluntarily give up Priority Dispatch. IWEA recommends that a review of market compensation for all forms of dispatch down is performed with and without Priority Dispatch (noting that such a review could follow implementation of the Regulation, and in any event should not delay the implementation of the Regulation). Older renewables which do not have subsidies linked to the physical production of power may be quite content to experience higher levels of dispatch down, as long as it is at least cost neutral to do so. Any barriers (procedural, commercial) for a non-subsidised renewable generator should be identified and removed.

6.9. Loss of Priority Dispatch due to Connection Agreement Change

The Regulation envisages loss of priority dispatch where there is a significant modification to a connection agreement. The term "significant modification" needs careful consideration, as it may lead to adverse consequences for issues such as repowering, and co-location of new renewables development with existing generation (which is being actively explored). It is IWEA's position that the interpretation of "significant modification" should not inadvertently prevent efficient forms of further renewable development where possible to do so. For example, a separately metered extension to a windfarm under an existing connection agreement should not trigger the loss of priority dispatch for the existing – most likely project financed – phase of the windfarm.

6.10. General Policy Review – Intermediary Example

There may be other elements of SEM policy which reference Priority Dispatch as a proxy for "renewable", for example in the Intermediary decision paper. A root-and-branch review is required to ensure no unforeseen circumstances arise due to the removal or Priority Dispatch.

7. Wider Policy Considerations

IWEA believe that the above interpretation is fully compliant with the Regulation. However, there are implications for wider policy developments in the Single Electricity Market.

7.1. Existing Generation Protected and Clean Energy Package

Existing renewable generation with priority dispatch will continue to face an equitable share of the need for constraint and curtailment in the market. Note that there are substantial policy changes for Ireland with respect to an increased renewable ambition for 70% renewable electricity by 2030. This makes the implementation of Article 13, paragraph 7 important for the continued sustainability of existing financed windfarms, as curtailment levels shared pro-rata may have a deleterious impact on projects' debt service cover ratios.

It is current policy that REFIT Generation return their constraint revenues to the PSO customer, reducing the amount of subsidy received by the windfarm. The Regulation sets out that generators should be compensated at the level of financial support. Article 13, paragraph 7(b) specifically states that "*financial support that would have been received without the redispatching request shall be deemed to be part of the net revenues.*" IWEA's position is that for REFIT projects, this means that REFIT payments should be based on actual generation plus any lost generation due to redispatching. We note that the current REFIT Proposed Decision Paper in relation to ISEM arrangements (CRU/19/129) proposes further consultation on this particular matter.

7.2. Renewable Targets and Investible New Renewable Generation

While Northern Ireland's share of the United Kingdom's renewable ambitions have yet to be clarified, Ireland has set new ambitious renewable targets. It is clearly important that new investment can participate in a regulatory environment where it is not entirely exposed to its marginal impact on technical limitations of the grid. The pro-rata treatment of tie-break non-energy constraint and curtailment under IWEA's position leads to a much more stable "projection envelope" of renewable dispatch, leading to efficient financing, lower costs to the consumers, and maximisation of delivered renewable energy.

For the avoidance of doubt, new generators will still have to manage risk of non-firmness (for constraint compensation), and energy actions like any other dispatchable non-renewable generator. Important market signals are therefore still sent to new generation investment.

7.3. Firm Access under Connection Policy

There is no compensation for constraint suggested in IWEA's proposals in this paper for producers that have accepted a connection agreement under which there is no guarantee of firm delivery of energy. Non-firm access should continue to send a signal to such generation; nevertheless, a complete non-firm connection policy where firmness is not delivered in a timely manner is simply not sustainable. It is against the spirit of the Regulation where firm access is referenced in respect of compensation for curtailment, and it increases the uncertainty and cost of renewables development, howsoever those costs are recovered through market or subsidy mechanisms, for the consumer due to the uncertainty it creates.

It is noted that the expression "a connection agreement under which there is no guarantee of firm delivery of energy" is also open to interpretation itself. It could be interpreted to only mean a permanently non-firm connection agreement. IWEA is also in receipt of correspondence from DG ENER, received via Wind Europe, which indicates that non-firm access should be the exception rather than the expectation.

That said, where non-firm windfarms operate the vast majority of the time with levels of constraint comparable to firm windfarms, the determination of firmness itself becomes esoteric. In circumstances where the consumer is largely ambivalent to the small out-turn constraint costs, non-firmness unnecessarily becomes a material financing risk for windfarms. This ends up costing the consumer more, particularly within the context of pay-as-bid renewable support auctions.

The importance of firmness for compensation for non-market redispatch brings greater scrutiny that the current definition of "firm access" is appropriate. It is IWEA's position that current methodology for the determination of firmness should be changed under both jurisdictions' enduring connection policy regimes to take greater cognisance of the principle that a generator should be considered non-firm only where there are potentially high costs to the consumer arising from material, enduring constraints.

IWEA references their pre-consultation submission to the CRU in relation to ECP-2 for further detail in relation to this matter.

Appendix 1: Implementation Considerations

It is noted that the Regulation comes into force on the 1st January 2020 and irrespective of implementation timeframes, generators are entitled to compensation based on the enduring design from that date.

RESS Auction

It is a working assumption that the new Renewable Electricity Support Scheme will want to incentivise delivered renewable energy. IWEA's "pro-rata for constraint and curtailment" proposal here means that projections of dispatch down for renewable generators participating in the RESS auction will be lower and in a much tighter range over the duration of a renewable generator's financing period. Greater projection certainty means greater levels of cheaper debt (which demands such certainty) can finance the windfarm. Cheaper financing costs in turn means cheaper offers into the RESS auction and lower costs for the PSO customer.

Non-Market Redispatch Compensation Calculation

Firm generators subject to non-market redispatch are subject to compensation under Article 13 paragraph 7 of the Regulation. Compensation for non-market redispatch at the Day-Ahead prices for generators out-of-support can be calculated by:

- Turning off the "Curtailment Charge" in the Balancing Market design.
- Paying back a decremental price of zero for all curtailment and for firm constraint, where there is an ex ante trade. This could be readily implemented in the Balancing Market for where the generator is a market participant (noting BMPCOP implications for renewables with non-zero marginal costs).
- Paying a Day-Ahead Price for curtailed volumes, and for firm generators' constrained volumes where the generator is not a market participant. This requires a new payment mechanism.

Compensation at the level of financial support for generators for non-market redispatch can be calculated by:

- Turning off the "Curtailment Charge" in the Balancing Market design.
- Paying the constrained volumes at (Financial Support Rate – Ex Ante Traded Price[10]) for all curtailment and for firm constraint for generators on feed-in tariffs. The Ex Ante Traded Price can be a submitted decremental offer or automatically calculated under the Balancing Market

[10] This is the achieved blended ex ante price from all trades in relation to the Day-Ahead Market and Intraday Markets. This calculation is already defined within the calculation for the Curtailment Charge.

design. It is IWEA's preference that whatever the contractual basis for this compensation, that the level of compensation is calculated automatically via a market rule, and therefore bypasses BMPCOP considerations much as the curtailment calculations do today.

- Paying back a negative decremental price of the value of any certificate forgone (ROC, REGO, GoO) arising for all curtailment and for firm constraint, where there is an ex ante trade. This could be readily implemented in the Balancing Market for where the generator is a market participant, again via a market rule rather than a submitted offer.
- Paying the equivalent supported prices as above (feed-in-tariff rate, or Day-Ahead plus certificate value) for curtailed volumes, and for firm generators' constrained volumes where the generator is not a market participant. This requires a new payment mechanism.

Non-Market Redispatch Compensation Funding (and Contractual Basis)

As noted above, the Balancing Market with modest modifications to the Trading & Settlement Code can implement most of the required compensation mechanisms. However, this does mean that compensation – sometimes at jurisdictional renewable support levels – will flow through the Imperfections Charge. If there were concerns around the reasonableness of the allocation, i.e. consumers in Ireland paying for ROC-based compensation, or consumers in Northern Ireland paying for REFIT/RESS-based compensation, then in the calculation of the annual Imperfection Charge rate an adjustment could be made to the appropriate pound sterling and euro rates.

For out-of-market generation (and generators without an ex ante trade) either an alternative contractual mechanism is required, or more material changes are required to the Trading & Settlement Code to integrate the required data from non-market participants into the settlement calculations. If an entirely different contract with the system operator (who is obliged to provide the compensation under the Regulation) is chosen to provide the required compensation, this could be funded via use-of-system charges.

New Generator TSO Scheduling and Dispatch

New renewable generators will not have priority dispatch. Correspondingly, they will not be automatically scheduled in the System Operators Security Constrained Unit Commitment or Security Constrained Economic Dispatch. New renewable generators will have to trade in ex ante markets to achieve a physical notification position like any other generator in the market. It is likely that market participant generators will have to submit physical notifications to the System Operator.

The TSO will also consider all non-priority dispatch renewable generation for energy balancing during economic dispatch. These generators will be subject to the same bidding code of practice as other generators, meaning that they can reflect their desire not to be used for energy balancing through low (negatively) priced decremental bids. If called (and they have a firm connection offer) they will be compensated according to the market rules. Constraints, which are subject to BMPCOP regulated offers, would be treated as non-market redispatch and treated accordingly under the proposed market rules above, and not their submitted offer.

Appendix 2: Sample Calculation

Scenario

This scenario is based on a single hour where curtailment is occurring, and there is more renewable generation (including new renewables without priority dispatch, and legacy priority dispatch generation) than required demand (including any exports), i.e. there is also an excessive generation event.

The curtailment occurs beyond the excessive generation event, because only 75% of instantaneous demand (system non-synchronous penetration, or SNSP) can be met by the renewable generation, which is all assumed to be "non-synchronous" generation.

New Renewable Available Production:	4000MW
Priority Dispatch Available Production:	3000MW
Demand and Interconnector Export:	6000MW
Maximum Demand Served by Non-Synchronous Generation:	4500MW (75% SNSP)

Dispatch down of New Renewables for excessive generation:	1000MW

The Dispatch down of 1000MW is delivered through "market-based" dispatch. This dispatch down has "Energy Balanced" the market, i.e. there is 6000MW of remaining renewables and 6000MW of demand. This dispatch down will only be compensated to the extent the generators which are dispatch down have an ex ante market trade, and that may be dependent on demand purchasing more than it required in the ex ante markets to match that trade.

Post Energy Balancing New Renewable Available Production (-1000MW):	3000MW
Post Energy Balancing Priority Dispatch Available Production (no change):	3000MW
Curtailment Required for Non-Synchronous Limit:	1500MW (25% SNSP)

The "Curtailment Required for Non-Synchronous Limit" of 1500MW is required to bring the renewables (all assumed to be non-synchronous) to 75% of instantaneous demand. This curtailment is non-market redispatch, and is shared pro-rata (in this case an equal 750MW) between priority dispatch and new renewable generation because there is is the same amount of available priority dispatch and new renewable generation.

Curtailed New Renewable Production (-1750MW):	2250MW: 43.75% total dispatch down

25% (gross percentage) of the total dispatch down for new renewables is compensated as per Article 13.

Curtailed Priority Dispatch Production (-750MW):	2250MW: 25% total dispatch down

All of the total dispatch down is compensated for Priority Dispatch generation as per Article 13.

As there is now only 4500MW of scheduled renewable generation, the balance of the 6000MW of demand has to be met by conventional generation.

Balance of Demand met by Conventional Generation:	1500MW