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22nd June 2020

By email to: Gina Kelly (gkelly@cru.ie) and Gary McCullough (Gary.Mccullough@uregni.gov.uk)

Re: Consultation Paper on the Implementation of Regulation 2019/943 in relation to Dispatch and Redispatch

Dear Ms Kelly and Mr McCullough,

DP Energy welcomes the opportunity to engage with the SEM Committee and respond to the consultation paper on the 'Implementation of Regulation 2019/943 in relation to Dispatch and Redispatch'.

DP Energy are a renewable energy company operating worldwide to develop renewable energy projects which are both sustainable and environmentally benign, with both onshore and offshore projects under development in Ireland.

DP Energy fully supports the Irish Wind Energy Association (IWEA) and Northern Ireland Renewable Industries Group (NIRIG) response to the consultation and would like to highlight the correct implementation of these Articles will play a large role in the timely delivery of 70% renewable electricity in Ireland and in meeting Northern Ireland's future renewable energy targets.

We support the positions taken by IWEA and NIRIG and wish to reiterate that the points raised in their consultation response are extremely important to ensure reduced investment risk in Ireland and Northern Ireland and will lead to the most cost-effective method of meeting 2030 renewable energy targets.

In conclusion, we would like to thank the SEM Committee for the opportunity to engage on this matter and look forward to continuing our work with you in future.

Yours sincerely,

Sara Armstrong

DP Energy Ireland Ltd

IWEA and NIRIG Response to the SEM Committee's Consultation Paper on the Implementation of Regulation 2019/943 in relation to Dispatch and Redispatch

(SEM-20-028)

June 2020

IWEA,
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Executive Summary

IWEA and NIRIG would like to thank the SEM Committee for the opportunity to respond to the Consultation Paper on the Implementation of Regulation 2019/943 in relation to Dispatch and Redispatch.

IWEA and NIRIG's response to the consultation has been structured to provide feedback on the areas of the consultation and Articles which we feel are of the highest priority. We have set out a background to our understanding of the Electricity Regulation in Section 2. In Section 3 we have noted several key clarifications and considerations which we believe will be crucial as next steps prior to any subsequent SEM Committee decisions or further consultations.

Section 4 and Section 5 then go through the main issues we believe are important for implementing Article 12 and Article 13 respectively. These sections contain our main considerations and we recommend should be the focus of the SEM Committee in reviewing this response. Finally, the response contains three appendices. Appendix A responds to the questions which the SEM Committee have set out in the document, referring to previous sections of the report for justification. Appendix B provides more details and examples on key clarifications and considerations which we believe need to be considered by the SEM Committee. Finally, in Appendix C we have summarised modelling analysis which has been carried out to support IWEA and NIRIG's consultation response.

We would like to set out the following positions from the outset:

Overall Implementation

- Noting the Electricity Regulation was signed off for almost a year prior to this consultation, and that the Regulation came into force on 1st January 2020, it is imperative that no further time is lost and a clear roadmap to implementation of Article 12 and 13 is given as soon as possible following this consultation. 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 as per Article 13. It is important that the next steps are cognisant of interactions with future RESS generators and existing REFIT & ROCs generators. The next steps will have a big impact on the development of the future Northern Ireland Energy Strategy and on delivering on Ireland's 70% renewable electricity target for 2030.

Article 12

- We believe a SEM Committee decision is required as soon as possible on the meaning of "subject to existing contracts concluded" at the time of the July 4th 2019 date which defines what are the last generators which receive Priority Dispatch - we believe this should refer to generator units which can become active under a contract concluded before 4 July 2019 including a REFIT/ROCs letter of offer or a corporate PPA.

- We believe a SEM Committee decision is required as soon as possible on the meaning of "significant modifications" in relation to a power generating facility which may result in the loss of Priority Dispatch for existing units. We also believe clear processes and transparency is needed on behalf of the System Operators as to when and why new connection agreements are "required" as per Article 12.

- We believe substantial engagement is required amongst industry, the Regulatory Authorities, System Operators and SEMO to understand how non-priority dispatch renewables will participate in the market, how settlement will work, and what market systems will be utilised in order to dispatch these units. In particular:
  - We strongly recommend the rules for bid-offer acceptance classification require further review, consultation, and impact assessment against different classes of generator, and ultimately appropriate governance of the rules.
  - We also strongly recommend the rules for submission of Final Physical Notifications (FPNs) for all classes of generation require further consultation, and those rules are impact assessed against different classes of generation.

Article 13

- It is our strong position that constraint of renewable generation which occurs on the power system today is a form of non-market based redispatch and therefore should be fully compensated up to the value of the unit's financial support. Quantifying constraint as non-market based redispatch is supported by several of the SEM Committee's own arguments in the consultation paper.
- While we agree with the RAs' interpretation of the level of compensation to which curtailed generators should be entitled described in the final paragraph of page 47 of the Consultation Paper, we strongly disagree with the RAs' interpretation of what is meant by compensation being "unjustifiably high". We believe that the RAs have adopted an incorrect and unlawful test and, as a consequence, none of the options set out in the Consultation Paper can be lawfully implemented.

- It is essential that any generators that receive revenues for redispatch in Ireland and are in receipt of a PSO levy payment are not then penalised for the receipt of these revenues under R factor reconciliation calculation.
- Under Article 13, a non-market participant renewable generator (i.e. de-minimis generator) which is subject to redispatch is due equivalent compensation to a participant generator. A separate compensation process could be designed and rules around FPNs and the deemed prices at which such generators are dispatched will need development.

Lastly, we would like to re-emphasise that the implementation of these Articles will play a large role in the timely delivery of 70% renewable electricity in Ireland and in meeting Northern Ireland's future renewable energy targets. Placing incentives on system operators to minimise constraint and curtailment, through the lawful implementation of Article 13, will reduce investment risk in Ireland and Northern Ireland and lead to the most cost-effective method of meeting 2030 renewable energy targets.

1. Introduction

The Irish Wind Energy Association (IWEA) and Northern Ireland Renewables Industry Group (NIRIG) welcome the opportunity to respond to the SEM Committee consultation on the 'Implementation of Regulation 2019/943 in relation to Dispatch and Redispatch'.

IWEA is a representative body for the Irish wind industry, working to promote wind energy as an essential, economical, and environmentally friendly part of our low-carbon energy future. NIRIG is a collaboration between IWEA and RenewableUK and is the voice of the renewable electricity industry in Northern Ireland. Together we represent a large majority of the renewable industry supply chain on the island.

IWEA and NIRIG have been active in discussions with the Regulatory Authorities, SEMO and the System Operators on this topic for several months and we welcome the decision to consult on Articles 12 and 13 of the Electricity Regulation together to ensure that a clear, coherent and streamlined solution is found. By doing so the Regulation can be delivered in full in a fashion that minimises costs to the end consumer.

IWEA and NIRIG's response to the consultation has been structured to provide feedback on the areas of the consultation and Articles which we feel are of the highest priority. We have set out a background to our understanding of the Electricity Regulation in Section 2. In Section 3 we have noted several key clarifications and considerations which we believe will be crucial as next steps prior to any subsequent SEM Committee decisions or further consultations.

Section 4 and Section 5 then go through the main issues we believe are important for implementing Article 12 and Article 13 respectively. These sections contain our main considerations and we recommend should be the focus of the SEM Committee in reviewing this response. Finally, the response contains three appendices. Appendix A responds to the questions which the SEM Committee have set out in the document, referring to previous sections of the report for justification. Appendix B provides more details and examples on key clarifications and considerations which we believe need to be considered by the SEM Committee. Finally, in Appendix C we have summarised modelling analysis which has been carried out to support IWEA and NIRIG's consultation response.

2. Background and Context of the Electricity Regulation

The European Union has several legal instruments at its disposal. These are used to make or coordinate policies, to take measures and initiate programmes, to facilitate the implementation of policies and to issue advice to Member States. Legal instruments are divided into two categories, binding, and non-binding instruments.

An EU Regulation has general application to Member States, is binding in its entirety and is directly applicable without the need for any national implementing legislation.[1] An EU Regulation also has direct effect, meaning that it can be relied on in a national court, and its provisions will override any inconsistent national law.[2] The aim of an EU Regulation is to ensure uniform implementation of European legislation, and the subject-matter of any implementing regulations serves that goal alone. This ensures implementation takes a similar shape in each individual Member State. This is unlike a directive, which allows the Member States freedom to choose the manner they see fit to fulfil the required objectives.

The strict implementation of an EU Regulation is therefore not something in respect of which a Member State (or any emanation thereof, including the RAs) has any discretion. The Regulation must be implemented strictly in accordance with its terms.

As you are aware, Articles 12 and Article 13 are components of the Electricity Regulation of the Clean Energy Package. The Electricity Regulation has direct effect and so the deliverance, in full, of Articles 12 and 13 is required by European law from the date of entry into force, which in the case of the Electricity Regulation was 1st January 2020.

While the publication of this consultation is welcome, we note our concern that the consultation is only occurring in May 2020, and that any implementation of the Regulation would appear to be several months away. We would strongly recommend that the Regulatory Authorities, SEMO, and the System Operators place a high priority on the next steps following this consultation so that Ireland and Northern Ireland become compliant with Regulation as swiftly as possible.

Noting the Electricity Regulation was signed off for almost a year prior to this consultation, and the Clean Energy Package has been expected and in various stages of drafting since 2015, it is

[1] Article 288 of the Treaty on the Functioning of the European Union (TFEU).
[2] *Van Gen den Loos* (case 26/62) EU:C:1963:1, at page 13

imperative that no further time is lost and a clear roadmap to implementation of Article 12 and 13 is given as soon as possible.

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.

Any further uncertainty on a live Regulation in a live market creates material commercial uncertainty, risk and therefore costs for all parties involved.

In the response below we summarise our key clarifications and considerations which are required as next steps following this consultation. We then summarise our positions on Articles 12 and 13 of the Electricity Regulation individually, before looking at how we believe they can be implemented together in the most coherent fashion. We set out the principles by which each Article should be implemented in our view, and we then respond to each question from the consultation, referring back to the principles and also putting forward supporting evidence for our positions.

3. Key Clarifications and Considerations for Next Steps Post-Consultation

IWEA and NIRIG believe there are certain questions raised in the consultation paper which can progress rapidly to a decision. These include:

- The meaning of "subject to existing contracts concluded" at the time of the July 4th 2019 date which defines what are the last generators which receive Priority Dispatch;
- The meaning of "significant modifications" in relation to a power generating facility, the consequences of which Priority Dispatch may be lost;
- Whether constraint is considered "market based" or "non-market based" redispatch; and
- A position on the legal principle of payments being "unjustifiably high" in the context of non-market redispatch compensation.

However, we believe that most of the detail in the paper should not progress to a decision at this time, and instead further consultation is required. In particular, there is a very significant body of work required to ensure common understanding across the industry, SOs, SEMO and RAs on how non-priority dispatch renewable units will trade in the market, how varying dispatch down categories would be applied to these units, and how settlement for these units will work.

In IWEA and NIRIG's view, the paper was incorrect in its assessment that self-dispatch and centrally dispatched markets are different in how difficult it is to differentiate between energy actions and non-energy actions. That early conclusion excused the need to examine this detail properly. However, this detail is vital. It is IWEA and NIRIG's contention that central dispatch market or not, dispatch and redispatch can be clearly identified <u>if there are clear rules in place to classify them, and those rules are consistent across treatment in dispatch and settlement</u>.

For the avoidance of doubt IWEA and NIRIG believe that the above four bullets by themselves will not give appropriate levels of "rule certainty" for RESS participants in the upcoming RESS 1 auction or any subsequent auctions. This is due to the important details which require further examination which we have listed below in four categories. Further details on these categories are provided in Appendix B.

- Generation declarations need to be appropriate for windfarms (including on an interim basis if required);
- Dispatch and redispatch need to be clearly proceduralised, given the importance of delivered energy to renewable generators;
- Classification rules need to be clearly defined, and aligned with the dispatch rules; and
- Settlement detail needs to be at least provided with principles, so it does not undermine policy.

4. Article 12

Article 12 provides for ending the designation of all but the smallest new renewable generation projects as priority dispatch. Priority dispatch is a status granted to certain technology types under the SEM and is a key pillar of the existing market. The following sections set out IWEA and NIRIG's understanding of Article 12 and considerations which we believe should be taken into account in any future decisions or consultations on the below topics.

4.1 Treatment of non-priority dispatch renewable generation

The principle benefit of priority dispatch in SEM is for the scheduling process of Priority Dispatch units to begin with the unit's availability rather than a Physical Notification (PN) based on its Ex-Ante Market traded position. It allows the market system to maximise the level of renewable generation scheduled to generate.

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 a provision for the priority dispatch status of renewable generation to be amended, 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 - out-of-support units who now rely solely on market revenues and 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 and would be unwilling to accept prices below €0/MWh. The market systems will need to be equipped to accommodate units which choose to opt out of priority dispatch in order to allow them to submit COD and TOD and participate in the market.

Non-priority dispatch renewables which submit COD and TOD will need to be able to respond to dispatch instructions from the system operator. At present, the system operators dispatch wind generation (and solar generation) in a limited form through the application of constraint and curtailment instructions using the Wind Dispatch Tool.

Conventional generators are currently dispatched by the system operators using EDIL. IWEA and NIRIG members have very serious concerns over the application of EDIL as a dispatch mechanism for non-priority dispatch variable generators. Due to its extremely manual nature and the fact that wind units do not use EDIL at all at present, the use of EDIL would cause very significant disruption to market participants and require significant costs to install and to train staff on this system. The use of EDIL would require manual entry of wind and solar units' availability on a very regular basis, and add a significant workload to the National Control Centre engineers in EirGrid and SONI who would need to manually accept each new availability declaration from wind and solar units.

In comparison, the use of the Wind Dispatch Tool, which is already a well-functioning dispatch mechanism, will erode the need for manual entry of availability from renewable units as this is automatic. It would also allow for automatic response from renewable units within seconds, as opposed to a manual acceptance of a dispatch instruction through EDIL. IWEA and NIRIG members recognise that there is no process currently for the Wind Dispatch Tool to accept FPNs which is a key requirement for renewables seeking to avoid running below acceptable prices. IWEA and NIRIG recommend the Wind Dispatch Tool is amended, or a purpose built suitable alternative system is developed, to allow this to happen.

IWEA and NIRIG have been informed that amending the market systems to do so will require non-trivial systems changes. However, IWEA and NIRIG are strongly of the view that current system limitations should not be allowed to determine the direction of future policy. It is core to the Electricity Regulation that renewable generation, as an increasingly significant proportion of the generation market, be afforded full access to trade in the internal market.

Furthermore, there will be times for energy balancing purposes that priority dispatch units will be required to be dispatched down after all market based resources have been utilised. To ensure fair and even burden sharing this should continue to be applied on a pro-rata basis among the priority dispatch units, using the hierarchies proposed.

In considering the interactions between Article 12 and Article 13, IWEA and NIRIG members believe that facilitating the access of non-priority dispatch units to become price makers in I-SEM will mean those units will choose to run less frequently at times of negative pricing or at times where priority dispatch generation is very high and there is no "space" remaining following energy balancing. The reduction of renewable generation at such times would lessen the requirement for redispatching units in the balancing market, thus reducing the impact on the end consumer and having a direct impact to any resulting compensation for dispatch down.

As set out in Section 3 of this response, there are considerable answers and clarifications required in order to understand how non-priority dispatch renewables will participate in the market.

The meaning of the FPN for controllable non-priority dispatch renewables should also be a matter of consideration. Under Article 6 (1), Balancing Market design should allow for non-discrimination between different market participant types, *"taking account of…the different technical capabilities* *of generation sources"*. Forcing wind units to submit FPNs on a like-for-like basis with conventional technical characteristics does not meet this high-level requirement of the Regulation. For example, an FPN from a non-priority dispatch controllable renewable generator may have the meaning "I wish to run at my available power based on the renewable resource", rather than a declaration of "I wish to run the following minute-by-minute forecast of my available wind output". Non-priority dispatch units which are obligated to submit both COD and TOD should have the right to choose whether to submit simple or complex COD and be settled for redispatch from their PNs in the same way as any other unit, noting that the PNs may have a different technical form to conventional generation to respect the technical characteristics of the generator pursuant to the non-discrimination required under Article 6 (1).

The introduction of such a category of unit is implicitly required under the Electricity Regulation and should significantly reduce the costs to the system operator, and ultimately the end consumer, of dispatching down renewable units under Article 13. As the majority of non-priority dispatch units will likely choose not to run at times when the market price is negative, this will take a potentially large volume of renewables off the system at such times and reduce the need to redispatch priority dispatch units. Furthermore, as a result of renewable generation which is out of subsidy support being able to price the costs of dispatch down, the need to reduce units which are in receipt of subsidies is further reduced. Consequently, the volumes of compensation paid to such units for non-market based redispatch, as required under Article 13, will decrease.

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

In November 2019, IWEA submitted a position paper[3] to the Regulatory Authorities outlining that our preferred position was point 3 - "*Where a unit becomes active under a contract concluded before 4 July 2019 including a REFIT letter of offer or PPA".*

IWEA and NIRIG remain convinced that it is critical this categorisation should be supported by the Regulatory Authorities as it has a direct impact on many projects which have energised since 4 July 2019, or are nearing completion of construction.

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 and NIRIG's position that the *"Without prejudice"* seeks to achieve protection for active projects with a clear route to

[3] IWEA Position Paper on Priority Dispatch and Compensation for Constraint and Curtailment, arising from EU Regulation 2019/943 - https://iwea.com/images/files/20191115-iwea-position-paper-on-priority-dispatch-and-compensation-for-constraint-and-curtailment.pdf

market that are actively making progress on financing and commissioning. The most objective measure of this is a wind farm that can demonstrate evidence of a route to market, such as a REFIT Letter of Offer or a CPPA before 4 July 2019.

Developers that 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, a 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.

IWEA and NIRIG support the suggestion of the Regulatory Authorities on the first point in relation to receiving commission programmes; however, we question why this criterion should be limited to the TSOs and not include distribution connections? We would also challenge whether every project is treated equally and receives a commissioning programme from the System Operators. In our experience, the process for receiving commissioning programmes varies considerably project to project and System Operator to System Operator.

In relation to the second point, the position on this is more complex as it opens the category of priority dispatch to a large quantity of generators. Projects that are eligible to be processed under the Enduring Connection Policy scheme, projects that have received a connection offer in Northern Ireland but not a connection agreement, and projects that have received a connection offer through the capacity remuneration market mechanism would all be eligible for priority dispatch. IWEA and NIRIG would question the legality of considering if being eligible to be processed for a connection offer constitutes a “contract concluded before 4 July 2019”.

We also query on what basis the RAs have concluded that the reference to “contracts concluded” is a reference to a Connection Offer or Agreement? Connection Agreements are entered into at very different times in different jurisdictions and, in some jurisdictions, there is no such thing as a connection agreement. For example, until recently generators in Denmark were simply afforded third party access to networks pursuant to either TSO (Energinet) rules or the Danish Energy Agency’s tender conditions. Given that the Regulation is strictly binding in accordance with its terms without further transposition, we do not believe that it can be a correct interpretation of this Article that the “contracts concluded” can be intended to refer to Connection Agreements as this would (i) make the Article meaningless in certain jurisdictions; and (ii) afford a fundamentally different treatment to different generators in different jurisdictions which would be incompatible with the principles of non-discrimination and equality of treatment. We therefore believe that the better interpretation is that this must refer to contracts which provide revenue streams to underpin the development, such as a REFIT, ROC or Corporate PPA.

As a matter of law, in order for a contract to exist, there must be a valid offer and acceptance. A generator that is eligible to be processed for a connection offer does not have an enforceable legal right to receive a connection offer, let alone an enforceable connection agreement. Once an offer is issued, a generator typically has 90 days to accept it and must satisfy any specified conditions precedent before the offer is considered to be validly accepted. The conditions precedent will include making a first stage payment, putting in place any bonds required by the system operator, and countersigning and returning the connection offer to the system operator. All of the conditions of acceptance must be satisfied before there is a legally binding agreement in place. If the relevant contracts are Connection Agreements (which we believe that they cannot be), as a matter of law the reference to "contracts concluded" must be interpreted as contracts that are legally binding and cannot include (1) generators who are eligible to be processed for a connection offer; or (2) generators who have received a connection offer which may or may not be validly accepted.

Furthermore, it is likely that units which operate under the RESS scheme will only be remunerated to their contract price if the Day Ahead price is greater than or equal to zero. As such, these units will need to be able to forego priority dispatch to avoid having financial losses inflicted on them if they cannot turn off in such circumstances. It is very likely that the same criteria would apply to any future renewable generator connecting in Northern Ireland once a new route-to-market becomes viable, and similarly they would want to be dispatchable to avoid times of negative pricing.

Therefore, it is the view of IWEA and NIRIG that as future renewable generation will quite likely seek to forego priority dispatch in any event, that the second category of units which are '*eligible to be processed to receive a valid connection offer'* should not qualify for priority dispatch as a 'contract concluded before 4 July 2019'.

We believe the focus of the Regulatory Authorities and System Operators should be on ensuring that non-priority dispatch generators can actively participate in the day-ahead and balancing markets by the time any such unit energises onto the power system.

Lastly, it is important the Regulatory Authorities and System Operators understand the potential impacts of allowing too much generation which is still in development to be allowed priority dispatch. IWEA and NIRIG commissioned MullanGrid to carry out analysis of the potential impact on dispatch down levels under a variety of scenarios for when the cut-off date for priority dispatch begins. The full details for this are provided in Appendix C.

As a caveat, this analysis assumes that all units with priority dispatch would seek to retain priority dispatch and ignores the impact of negative pricing in that decision, and the consideration that conventional units may bid in at negative prices to achieve a day-ahead position during energy balancing. The analysis shows that the current position of the RAs where any project '*eligible to be processed to receive a valid connection offer'* would receive priority dispatch, results in a 3% increase in a dispatch down for energy balancing reasons for 'new' wind generation compared to our preferred position which allows only units which can become *active under a under a contract concluded before 4 July 2019* to obtain priority dispatch. This would result in a substantial increase in auction bid prices for these projects to counter this, if such a scenario materialised.

4.3 Loss of priority dispatch due to 'significant modifications'

We note and agree with the Regulatory Authorities' statement (Section 3.6 second paragraph) that "*The RAs are concerned that this may create a barrier to the repowering of existing wind farm sites for example and the implementation of the most effective use of network assets in terms of accommodating renewable generation and may introduce perverse incentives to avoid necessary or useful modifications where they introduce the requirement for a new connection agreement".*

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 restated connection agreements are issued to address, for example, a separately metered extension to allow for co-location of new renewables development with existing generation. An amendment of an existing connection offer (whether or not restated at the same time that it is being amended) is not as a matter of law a "new connection agreement". It is the same connection agreement, albeit amended. This is a well-established legal principle.

It is IWEA and NIRIG's position that a new connection agreement by itself does not trigger the loss of priority dispatch; priority dispatch is lost if there is a material change to a metered Generator Unit (in SEM terminology) that has <u>required</u> a new connection offer. If a new connection agreement is entered into for policy reasons or convenience, but the relevant modification could have been affected by amending the existing connection agreement, then it necessarily follows that a new connection agreement is not <u>required</u>. Article 12 only requires that there is significant modification to a power-generation facility where a new connection agreement is required, not when a new connection agreement is entered into for convenience but the modification could have been implemented without the new agreement.

Additionally, the merging of 2 units with priority dispatch should not result in the units losing priority dispatch for the sum of the MECs that had priority dispatch previously. Technical, commercial or administrative grid modifications to a project's connection agreement by IPP and/or SO should not trigger loss of priority dispatch where the following principle prevails:

No 'new' grid capacity will be created with priority dispatch status (i.e. a generator which becomes active under a contract concluded after 4 July 2019 as per section 4.2). Where 'old' and 'new' capacity shares the same connection, it must be separately dispatchable and metered units to allow for the 'old' capacity to maintain priority dispatch.

IWEA and NIRIG would also like to highlight that there are currently a number of projects with modifications in train. Some of these projects have open ECP-1 connection offers for REFIT extensions, while other modifications are ongoing and required in advance of RESS bids, therefore it would be very beneficial if this point around modifications could be clarified as a high priority following this consultation as there are several projects delaying beneficial modifications as a result of the lack of clarity on this point.

Loss of priority dispatch in those circumstances would have serious consequences for any project-financed asset. It is IWEA and NIRIG's position that the interpretation of "significant modification" should not inadvertently prevent efficient forms of further renewable development where possible to do so.

Article 12 allows for generators with priority dispatch to voluntarily give up priority dispatch. Older renewables which do not have subsidies linked to the physical production of power may be 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.

We believe clear processes and transparency are needed on behalf of the System Operators as to when and why new connection agreements are "required" as per Article 12.

4.4 Additional considerations

Several further IWEA and NIRIG positions in relation to Article 12 are put forward in the answers to the SEM Committee's questions in Appendix A. These include views on the new hierarchy(ies) of priority dispatch put forward by the SEM Committee in the consultation paper, including renewable hybrid units such as co-firing fossil and biomass (whose omission in the consultation paper appears to be an oversight), and the treatment of de-minimis units.

5. Article 13

Article 13 of the Electricity Regulation sets out how redispatching is governed, outlines objectives for System Operators to minimise redispatch, and how financial compensation for redispatched generation, energy storage or demand response is facilitated.

Article 13 sets out that generators who are subject to non-market based redispatch should be compensated for redispatch up to their net revenues including any financial support (such as REFIT, ROCs or Corporate PPAs) foregone as a result, unless they have accepted a connection offer with no guarantee of the firm delivery of power.

5.1 Compensation for constraint

IWEA and NIRIG can see no basis for the assertion in the consultation that constraint actions can be considered as market based redispatch. Units that are subject to constraint actions are not chosen with reference to any submitted prices or to the supply/demand balance but solely due to local system limitations. Furthermore, the existing market systems do not consider TOD or COD from wind or solar generation. Table 3 of the consultation paper confirms that wind and solar generators "may submit Physical Notification (PN) but this is not currently used in the scheduling and dispatch process by the TSOs". Therefore, following the arguments put forward in the consultation paper itself, it cannot be interpreted that constraint actions for wind generation could be considered anything other than non-market based redispatch.

It is our strong position that constraint of renewable generation which occurs on the power system today is a form of non-market based redispatch and therefore should be fully compensated up to the value of the unit's financial support.

5.2 Compensation for curtailment

5.2.1. Introduction

The consultation paper correctly defines curtailment as non-market based redispatch. However, IWEA and NIRIG strongly believe that the firmness of a grid connection has no relevance for the application of curtailment, only for constraint, and as a result, both firm and non-firm generation should be compensated under Article 13 for curtailment. We note that SEM-13-010 specifically states that "*A pro rata approach to curtailment will provide certainty of equal burden sharing across all wind generators, irrespective of the level of firmness / market access which the generator enjoys*". Consequently, it should follow that both firm and non-firm generators should be compensated for curtailment as to do otherwise would go against the principle of '*equal burden sharing across all wind generators, irrespective of the level of firmness / market access which the generator enjoys'*.

We note that the I-SEM market has not received a derogation from Article 13 and that it was therefore required by European law to be compliant with the Article from 1st January 2020. Therefore, generators who have been subject to non-market based redispatch will need to be compensated from 1st January 2020, as to do otherwise is in breach of EU law.

While we agree with the RAs' interpretation of the level of compensation to which curtailed generators should be entitled, described in the final paragraph of page 47 of the Consultation Paper, we strongly disagree with the RAs' interpretation of what is meant by compensation being "unjustifiably high". We believe that the RAs have adopted an incorrect and unlawful test and, as a consequence, none of the options set out in the Consultation Paper can be lawfully implemented. We have therefore not responded to Consultation Question 15 in relation to the options, but instead have set out below detail of what is required to properly implement Article 13(7).

The purpose of Article 13(7) is to ensure that where generators are subject to non-market based redispatch they are fully compensated for the opportunity cost (or cost, as applicable) of redispatch, such that they are indifferent to whether or not they are redispatched (i.e. they are left in the same financial position). Article 13(2) makes it clear that, save for certain limited circumstances, redispatch must be market based. Where a generator is subject to market based redispatch, the generator can bid a price at which it is prepared to be redispatched. In doing so, it will bid the price at which its opportunity cost (or cost, as the case may be) associated with the redispatch is covered. This will ensure that it is fully compensated for being redispatched.

Where non-market based redispatch is required, Article 13(7) ensures that the compensation received by a generator that is subject to non-market based dispatch is no less than the remuneration received by a generator that is subject to market based dispatch. This is important for a range of reasons, including that generators are not prejudiced by a failure of a Member State to implement market based mechanisms for redispatch as envisaged by Article 13(2); Member States are not incentivised to opt for non-market based rather than market based Redispatch mechanisms in breach of Article 13(2); and perhaps most importantly, markets are not designed with structural barriers to the development of renewables and achievement of the EU's climate objectives. In order to ensure that these objectives are achieved, it is critical that Article 13(7) is implemented in Ireland as intended.

Article 13(7) provides as follows:

> *"Where non-market based redispatching is used, it shall be subject to financial compensation by the system operator requesting the redispatching to the operator of the redispatched generation, energy storage or demand response facility except in the case of producers that have accepted a connection agreement under which there is no guarantee of firm delivery of energy. Such 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."*
>
> (emphasis added)

Article 13(7) therefore requires that where a generator is redispatched up, it is compensated for the cost of such upward redispatch in the form of incremental costs. Where a generator is redispatched down, it must be compensated for the opportunity cost of such downward redispatch in the form of foregone net revenues (including renewable supports) or, where higher, incremental costs of such downward redispatch (for example in a HE-CHP plant needed to replace a heat load). Article 13(7) contains a methodology for calculating the minimum level of this level of compensation, allowing that it can be higher but can never be lower than the level calculated in accordance with the Article.

Article 13(7) also contains a saving provision that ensures that if the application of the methodology results in a generator being overcompensated or undercompensated (in each case unjustifiably), the Member State may adopt a blended methodology for calculating the level of compensation. In all cases, Article 13(7) contains an absolute requirement that (i) a generator that is subject to non-market based redispatched is compensated by the system operator; and (ii) that the level of compensation is at least equal to the higher of the actual costs associated with the redispatch or the opportunity cost associated with the redispatch, save where this results in unjustifiable over or under compensation to the generator.

5.2.2. RA Interpretation of Article 13(7)

In the Consultation Paper, the RAs reach the proposed conclusion that the provision of financial compensation to generators subject to curtailment based on the net revenues from the day-ahead market, including any financial support that would have been received, represents an unjustifiably high level of compensation, with undue burden placed on electricity consumers. In reaching this conclusion the RAs cite a number of factors to which they have had regard including: (i) "*the balance of risk between consumers and generators*"; (ii) "*the utility of curtailed electricity*"; (iii) "*the limited funding available to invest in programmes to reduce the overall level of curtailment and facilitate higher levels of renewables on the system*"; (iv) the "*high level of instantaneous renewable generation in the SEM in comparison to the majority of EU Member States*"; (v) "*specific characteristics in the SEM in relation to system wide curtailment that are not reflected in other EU Member States*"; (vi) the fact that "*one of the SEM Committee's primary responsibilities is to protect the interests of electricity consumers on the island of Ireland*" and "*the inclusion of compensation of curtailment within DBCs up to the level outlined in Article 13(7)(b) would present an additional cost and risk to consumers based on the level of support provided to renewable generators and the DAM price over time*"; and (vii) "*the differences between the jurisdictional renewable energy support schemes which generators currently benefit from or will benefit from in future, including the total MW in support, capacity factors and support prices per MWh*".

It is respectfully submitted that the approach taken by the RAs to interpreting Article 13(7) misunderstands the nature of an EU Regulation, and the process described by the RAs in reaching the conclusion in the Consultation Paper is in breach of Ireland's obligations under Article 288 of the Treaty on the Functioning of the European Union (TFEU). Furthermore, the RAs' interpretation of Article 13(7) misconceives both the express wording and legislative intent of the Regulation, while being at odds with the plain English wording of the Article, the legislative history of the Article or any other interpretation of the Article that we have been able to discover in other jurisdictions. Each of these points is addressed in turn below.

5.2.3. Status of a Regulation under EU Law

An EU Regulation has general application to Member States, is binding in its entirety and is directly applicable without the need for any national implementing legislation.[4] An EU Regulation also has direct effect, meaning that it can be relied on in a national court, and its provisions will override any inconsistent national law.[5] The strict implementation of an EU Regulation is therefore not something in respect of which a Member State (or any emanation thereof, including the RAs) has any discretion. The Regulation must be implemented strictly in accordance with its terms.

It is clear from the Consultation Paper that the CRU has had regard to a wide range of policy considerations and obligations under domestic law in proposing its implementation of Article 13(7). This gives primacy to domestic law over an EU Regulation and is not permissible. While it is true that SEMC has duties in relation to the discharge of its statutory functions, any such duties are subservient to the provisions of Article 13(7). The RAs are bound by the Regulation in accordance with its terms and must implement it strictly. That the RAs have had regard to domestic statutory duties in interpreting an EU Regulation is a breach of both the Regulation and Article 288 of the TFEU.

5.2.4. Literal Interpretation of Article 13(7)

We agree with the SEM Committee's view that curtailment in the SEM represents non-market based redispatch within the meaning of Regulation 2019/943. Giving the words of Article 13(7) their ordinary meaning, the system operator is obliged to financially compensate producers in the event of curtailment. The second sentence provides how financial compensation shall be calculated, being the higher of limb (a) or limb (b), <u>or</u> if the higher of (a) or (b) is unjustifiably low or unjustifiably high, a combination of limb (a) and limb (b).

The reference in Article 13(7) to "unjustifiably low" or "unjustifiably high" pertains solely to the "compensation" that is required to be paid by the Article. The "compensation" to which this refers is the compensation to be paid by the system operator <u>to the generator</u> to compensate it for the opportunity cost (or cost) of the redispatching. It is therefore clear that the reference to "unjustifiably low" or "unjustifiably high" is a test of whether <u>the generator</u> is overcompensated or undercompensated, not whether the compensation to which the generator is lawfully entitled is, or is not, a unjustifiable burden on anyone else. In order to determine whether the generator is overcompensated or undercompensated, one must look to what "*would have been received without the redispatching request*". If the compensation equals what would have been received,

[4] Article 288 of the Treaty on the Functioning of the European Union (TFEU).

[5] *Van Gen den Loos* (case 26/62) EU:C:1963:1, at page 13

then the generator has been appropriately compensated for its opportunity cost and has not been overcompensated or undercompensated.

The overall cost to consumers is not referred to in Article 13(7), nor are any of the other matters to which the RAs have had regard, as indicated by the Consultation Paper. It is therefore clear that "unjustifiably low" or "unjustifiably high" do not and could not pertain to a burden on consumers; and any considerations in relation to the characteristics of the SEM or the jurisdictional support schemes are irrelevant considerations and it is unlawful to have regard to them. Furthermore, the suggestion that "unjustifiably low" or "unjustifiably high" could be intended to pertain to a burden on consumers clearly makes no sense in circumstances where an additional financial burden on consumers could, by definition, never be unjustifiably low. The interpretation of the RAs is therefore not sustainable on the face of the Regulation.

5.2.5. Purposive Interpretation of Article 13(7)

The literal interpretation of Article 13(7) is also consistent with the overall purpose and objectives of the Regulation. The Recitals emphasise the importance of flexibility, decarbonisation, innovation and the development of renewable energy.[6]

Recital 23 provides that "*While decarbonisation of the electricity sector, with energy from renewable sources becoming a major part of the market, is one of the goals of the Energy Union, it is crucial that the market removes existing barriers to cross-border trade and encourages investments into supporting infrastructure, for example, more flexible generation, interconnection, demand response and energy storage*". Similarly, Recital 34 provides that "*The management of congestion problems should provide correct economic signals to transmission system operators and market participants and should be based on market mechanisms.*" Article 13(7) sends a clear market signal encouraging investment into supporting infrastructure to minimise redispatch, such as curtailment, including more flexible generation, interconnection, demand response and energy storage. This objective is substantially undermined if Member States were permitted to ignore the requirements of Article 13(7) and make generators bear the cost of curtailment, rather than system operators, simply because the price signal was greatest. When the overall cost of redispatch is greatest, it is more important that Article 13(7) be strictly implemented.

Curtailment is outside of the control of generators. The purpose of financially compensating generators in this way is to ensure that they are indifferent to non-market based redispatch, and in turn promote the development of renewable power-generating facilities.

[6] Recitals are non-binding, but are relied on by the CJEU to interpret the purpose of an EU regulation.

5.2.6. Interpretation of Article 13(7) in other Jurisdictions

The approach taken by the RAs to interpret Article 13(7) is markedly at odds with any other interpretation of this Article in any other EU jurisdiction. For example, the Belgian National Regulatory Authority, Commission de Regulation de l'Electricite et du Gaz (CREG) recently interpreted the requirements of Article 13(7) as follows[7]:

> "*Production units which are redispatched downwards are remunerated (compensated according the CEP) for their opportunity costs. This opportunity cost corresponds to the profit they would have made by selling their energy in the day-ahead market coupling, being the difference between the dayahead market clearing price and the variable cost of production or the bid price for being redispatched downwards. This difference is also referred to as the "infra-marginal rent". In contrast, units which are redispatched upwards do not have this opportunity loss since they had not been selected in the dayahead market and hence did not make any profit in that day-ahead market. The upwards redispatching units are only remunerated for the variable cost of production or at bid price*." (emphasis added)

In the same study, CREG noted that Article 13(7) clearly indicated that generators that are redispatched should be compensation for loss of profit, stating that[8]: "*The compensation of market players (redispatched down) for the loss of profit is clearly indicated here. The interaction of this sound principle with the existence of a zonal price means that market players may be paid for not producing.*" (emphasis added)

Similarly, in a recent report commissioned in October 2019 by the German Federal Ministry for Economic Affairs and Energy on cost or market based redispatch procurement in Germany,[9] the following was observed at page 13:

> *"As part of redispatch, transmission system operators instruct generation facilities and storage facilities to increase or decrease generation in order to change electricity flows in the grid to avoid overloading network elements. Participation in redispatch is mandatory for most generators; generators under 10 MW are excluded so far, in future only small plants under 100 kW will be excluded. Operators are subsequently compensated for costs incurred and lost profits and are thus financially indifferent to redispatch provision. The aim*

[7] https://www.creg.be/sites/default/files/assets/Publications/Studies/F1987EN.pdf at paragraph 46.
[8] https://www.creg.be/sites/default/files/assets/Publications/Studies/F1987EN.pdf at paragraph 29.
[9] https://www.bmwi.de/Redaktion/EN/Publikationen/Studien/future-redispatch-procurement-in-germany.pdf?__blob=publicationFile&v=2

of making operators financially indifferent to redispatch provision is to avoid strategic bidding behavior and other feedback from congestion management to the electricity market."

It is respectfully submitted that the abovementioned interpretations of the Belgian and German authorities reflect the correct interpretation of Article 13(7) and generators in the SEM that are subjected to non-market based Redispatch should be compensated on the basis of their opportunity cost, such that the generators are indifferent to the redispatch and a clear price signal is sent to facilitate investment in "supporting infrastructure" within the meaning of Recital 23 of the Regulation.

5.2.7. Legislative history of Article 13(7)

The RAs' view that the overall costs of financial compensation should not be unjustifiably high from the perspective of the consumer is inconsistent with the early drafts of Regulation 2019/943. The initial concern was that the compensation should not be "*unjustifiably low*". The European Commission's initial proposal for the Article 13(7) simply stated that the financial compensation paid to generators which are the subject of non-market based redispatch should be the higher of the current limb (a) and limb (b).[10]

As the draft Regulation progressed through the ordinary legislative procedure, the wording of Article 13(7) was amended. In November 2017, one of the drafts considered by the Council introduced the following proposal: "*Financial compensation shall at least be equal to the highest of the following elements or a combination of them if applying one of the elements would lead to an unjustifiably low compensation:…*"[11]. The focus of this amendment was therefore very clearly to ensure that generators were not undercompensated; consistent with the language regarding the financial compensation being at least the equal of the higher of the two limbs. The fact that the concern was with under compensation, rather than overcompensation, clearly reveals that there was no concern regarding burden on consumers.

On 6 December 2017, a further amendment was proposed as follows: "*Financial compensation at least be equal to the highest of the following elements or a combination of them if applying one of the elements would lead to an unjustifiably low or unjustifiably high compensation*".[12] Given that it is clear that the burden on consumers was irrelevant to this Article prior to the 6 December 2017 amendment, it is equally clear that it remains irrelevant to this Article following the 6 December

[10] http://data.consilium.europa.eu/doc/document/ST-15135-2016-REV-1/en/pdf
[11] https://data.consilium.europa.eu/doc/document/ST-14625-2017-INIT/en/pdf
[12] https://data.consilium.europa.eu/doc/document/ST-15237-2017-INIT/en/pdf

2017 amendment. The subject matter of the Article does not change as a result of the introduction of a control on overcompensation as well as under compensation.

In our view, the only way that this can be interpreted is that generators should not receive financial compensation that is unjustifiably low or unjustifiably high. In other words, a generator should be in the same position that it would have been in but for the fact that it was curtailed. The introduction of the concept of "*unjustifiably low*" financial compensation in the first instance demonstrates that the primary concern was that, even if the higher of limb (a) or (b) was applied, generators that are curtailed should not be left in a worse position than the position that they would have been in if they were not curtailed. By the same measure, generators should not be overcompensated, or left in a better position as a result of being curtailed (for example, making a saving on variable costs such as fuel).

5.2.8. Costs of Compensation

IWEA and NIRIG do not believe an adequate assessment of the costs of dispatch down has been completed by the RAs. The range of €40 - €140 million put forward in the paper, only for curtailment of firm generators, takes a very pessimistic view of potential market outcomes over the coming decade. As evidenced in the modelling which MullanGrid carried out on behalf of IWEA and NIRIG, provided in Appendix C, curtailment levels do not exceed 4.5% in any scenario by 2030. We believe the RAs' figures include significant volumes of energy balancing in their assessment - which is not subject to compensation. We therefore believe the analysis which the RAs have used to be flawed and conclusions derived from the analysis to be invalid.

5.3 Re-allocation of risk as a result of compensation and consumer benefits

One critical point which the consultation paper does not discuss in relation to the full implementation of Article 13, is that this will reallocate a significant forecasting risk faced by renewable developers to the System Operator – that of constraint and curtailment. In IWEA and NIRIG's view this reallocation is welcome as the System Operators are best placed to manage and mitigate this risk, as opposed to a renewable generator owner who has no control over the future levels of constraint or curtailment once connected to the power system.

Under REFIT and ROCs, the tariff and top-up prices were set by Government and the constraint and curtailment risk was with developers who had to absorb any cost within the available REFIT tariffs or ROCs top-up. However, the current context for wind farms in the development pipeline is significantly different as it is wind farm developers that will be determining the price of renewable development via their RESS auction bids. This is likely to be the case with any future support scheme in Northern Ireland also. This means projects have to take a 25-30 year view of future constraint and curtailment levels to factor into their financial models and come up with a price under which they can build.

Future constraint and curtailment levels are extremely difficult to project, and wind farms must factor in a certain amount of additional risk in their calculations to account for volatility. With a 70% RES-E target in Ireland, and major system changes and grid reinforcements required to deliver this target, there is a lot less certainty on future constraint and curtailment levels. For example, a recent SEAI funded study estimated that curtailment levels could increase to 44% and we would need over 21GW of installed wind capacity to meet 70% RES-E if no system measures are put in place from today to increase SNSP levels and alleviate operational constraints such as Minimum Generation levels.[13] In relation to constraints, EirGrid's ECP-1 constraint reports project potential constraint levels of between 11-12% in Galway, 26-28% in Mayo[14] and 12-14% in Donegal[15] by 2022, with increasing levels of renewable generation connecting in these areas. These reports do not even account for projects which will be connecting under future ECP batches that are likely to impact constraints even further. In addition, EirGrid's *Tomorrow's Energy Scenarios 2019 System Needs Assessment* report identified the need for grid development in all scenarios analysed across all regions of the country.[16]

This leads to considerable uncertainties that developers need to factor in when trying to make provisions for future constraint and curtailment. As a result, modelling results are likely to be over a much wider risk band when a plausible range of input assumptions are considered. While the Terms and Conditions for RESS 1 have a safeguard in place to provide some support should curtailment exceed 10% for two consecutive years,[17] this does not account for dispatch down as a result of constraints or energy balancing. As detailed in Section 5.2.8, curtailment is unlikely to reach these levels, particularly if the right incentives are placed on the system operator to minimise curtailment. The full implementation of Article 13 as directed in the Electricity Regulation would put the right incentives on the party best placed to manage and reduce this.

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[13] https://www.seai.ie/data-and-insights/seai-research/research-projects/details/identifying-the-relative-and-combined-impact-and-importance-of-a-range-of-curtailment-mitigation-options-on-high-rese-systems-in-2030--2040

[14] http://www.eirgridgroup.com/site-files/library/EirGrid/ECP-1-Solar-and-Wind-Constraints-Area-B-v1.1-April-2020.pdf

[15] http://www.eirgridgroup.com/site-files/library/EirGrid/ECP-1-Solar-and-Wind-Constraints-Area-A-v1.0.pdf

[16] http://www.eirgridgroup.com/site-files/library/EirGrid/EirGrid-TES-2019-System-Needs-Assessment-Report_Final.pdf

[17] https://www.dccae.gov.ie/documents/RESS_1_Terms_and_Conditions.pdf

If full compensation for non-market based redispatch is not provided for, renewable generators will therefore be charging consumers for a cost, via their auction bids, which they are very poorly placed to find solutions for. These costs will then be locked in for up to 16.5 years under the term of the RESS support. It is highly unlikely that the cost factored into a wind farm's bid to take account of this uncertainty will reflect the true cost of constraint and curtailment. In the future, consumers will be paying for this either directly (through compensation for non-market based redispatch) or indirectly (where onshore and offshore developers incorporate their assumptions into auction bids).

Commercially efficient contracts allocate risk to the parties best placed to manage them. Developers have almost no ability to manage these risks post RESS auction bid, whereas those who are ideally placed to reduce and even remove dispatch down are the Regulatory Authorities and System Operators, by either adjusting the electricity market rules to incentivise solutions, such as through the DS3 programme, or by building the solutions directly. It is important to acknowledge that generators should not be incentivised to build renewable capacity where it is not required or where costs to the consumer from dispatch down compensation would be excessive (e.g. a non-firm generator in a highly constrained area of the country). It is important that strong locational signals are sent to generators but these should only be at a point in a project lifecycle where they can respond to such signals i.e. when they choose a location or choose to invest/construct. After this, it is only the System Operators and Regulatory Authorities that can manage dispatch down costs.

The reallocation of this risk will lead to lower prices in competitive renewable generation auctions throughout this decade. In the case of Ireland, this consequently will lead to a reduced contribution required from the PSO levy compared to what would otherwise have been the case had the risk remained with the renewable developer. While there will be a resultant increase in the costs of compensation, the compensation cost will reflect the *actual* costs of constraint and curtailment, rather than the forecasted costs by a renewable developer which will firstly never be correct, and secondly include an additional risk premium in the bid price. The reallocation of costs to the System Operators provides the correct signals to the right parties who are then incentivised to implement the solutions to minimise these costs.

For example, if just €1/MWh can be saved on the volume of energy to be procured over the entirety of the RESS scheme - 13.5 TWh according to the RESS High Level Design - the savings to the electricity consumer in Ireland, through a reduced PSO levy, over the entire 15 year contract duration for RESS projects, is €202.5 million.

Everoze, in association with IWEA, have recently published a report, *Saving Money*, which shows that the combined costs of constraint and curtailment could add up to €13.50/MWh onto the bid price of onshore wind energy in the RESS auctions.[18] If it is assumed the same price is attributable to offshore wind and solar generation, then the overall saving to the PSO Levy over the duration of RESS for compensating for curtailment and constraint is in excess of €2.7 billion over the RESS scheme. If that €2.7 billion is averaged out over 15 years, the saving to the consumer will be over €180 million per annum - well in excess of the most pessimistic forecast of the costs of compensation presented in the consultation paper.

Finally, allocating the management of constraint and curtailment risk to the System Operators will focus action towards addressing the underlying system limitations driving constraint and curtailment actions in a timely manner. Critical to this will be funding for the DS3 programme. IWEA and NIRIG are very concerned with the sentiment expressed in section 4.4 of the SEM Committee consultation paper which appears to imply if compensation is provided for non-market redispatch, as required from Article 13, that it will impact revenues available for the DS3 programme and System Services in future. The logic of this seems flawed, as progressing the DS3 programme and the development of zero-carbon System Services will lead to reduced levels of non-market redispatch and consequently less compensation needing to be provided. The '*Store, Respond and Save*' report[19] published by Baringa in December 2019 shows dramatic reductions in curtailment, dispatch balancing costs (at least €117 million per annum by 2030), and carbon reductions if all System Services are provided by zero-carbon service providers. These providers will only be incentivised to invest and develop these technologies if the correct investment signals are in place through the DS3 programme. Sentiment such as that expressed in the consultation paper appears to overlook the overall cost reductions and consumer & environmental benefits possible through continued System Services investment and serves to increase investment risk and uncertainty for prospective developers.

5.4 Consideration of the R-factor calculation for the PSO levy arrangements

Whilst outside the direct scope of this paper, it is essential that any generators that receive revenues for redispatch in Ireland and are in receipt of a PSO levy payment are not then penalised for the receipt of these revenues under R factor reconciliation calculation. To do so would be both against the direct text of the Article, and the spirit of what the Article was seeking to introduce - removal of risk to future revenue which is attributable to dispatch down. A correction for this could

[18] Saving Money - https://www.iwea.com/images/files/final-iwea-70by30-saving-money-report-may-2020.pdf
[19] Store, Respond and Save - https://www.energystorageireland.com/wp-content/uploads/2020/02/Energy-Storage-Ireland-Baringa-Store-Respond-Save-Report.pdf

be done simply by excluding the CDISCOUNT and CCURL charges from the R factor reconciliation calculation.

5.5 Optimisation of Articles 12 and 13

Article 12 provides the opportunity for non-priority dispatch units to manage their dispatch through submitted commercial offer data and provide an opportunity for the units not to run during times where market price is negative. Article 13 provides compensation for units which are subject to non-market based redispatch to the net value of their lost generation – i.e. including lost financial supports such as REFIT, ROCs, GoOs, REGOs, or Corporate PPAs top-ups.

IWEA and NIRIG believe that these payments should be recovered in a fashion that is fair and equitable to all and which could be implemented by a modification to the Trading and Settlement Code. Special arrangements will be required for de-minimis generation where subject to non-market redispatch. As noted above, given that the I-SEM market does not have a derogation to Article 13 of the Electricity Regulation which went live on January 1st 2020, the compensation would need to be effective from January 1st 2020.

It is IWEA and NIRIG's position that where compensation cannot be paid through the existing market systems - e.g. implementation delays, non-retrospective nature of the Balancing Market system design, compensation for curtailment pursuant to Article 13 for de minimis generation - a separate compensation process should be devised which allows for retrospective payments and payments to all participants.

A carefully considered implementation of Articles 12 and 13 can minimise any negative impacts to the end customer by reducing the development risk to units being developed in Ireland and Northern Ireland, which will lead to reduced bid prices in future renewable generation auctions. This will also provide an improved investment signal for renewables, aiding the efforts of Ireland and Northern Ireland to reach their 2030 climate targets.

The fact that this would reduce the volume of acceptances on priority dispatch units, by moving the accepted volume to non-priority dispatch units, would alleviate the issues that arose under the highly contentious Modification 10_19 which prevented priority dispatch units setting price. The modification was rejected by the Modification Committee and then implemented by the SEM Committee. Furthermore, if dispatching down of priority dispatch units is minimised, the imbalance price will be more reflective of the true market outcomes. This further enhances the transparency of the market signal provided by the balancing market.

6. Summary

IWEA and NIRIG would again like to thank the SEM Committee for the opportunity to respond to the Consultation Paper on the Implementation of Regulation 2019/943 in relation to Dispatch and Redispatch.

IWEA and NIRIG's response to the consultation has been structured to provide feedback on the areas of the consultation and Articles which we feel are of the highest priority. We have set out our positions and understanding of Article 12 and Article 13 in detail and we have highlighted the primary clarifications needed as soon as possible to progress the implementation of these Articles as soon as possible.

In summary, our primary positions are:

Overall Implementation

- Noting the Electricity Regulation was signed off for almost a year prior to this consultation, and that the Regulation came into force on 1st January 2020, it is imperative that no further time is lost and a clear roadmap to implementation of Article 12 and 13 is given as soon as possible following this consultation. 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 as per Article 13. It is important that the next steps are cognisant of interactions with future RESS generators and existing REFIT & ROCs generators. The next steps will have a big impact on the development of the future Northern Ireland Energy Strategy and on delivering on Ireland's 70% renewable electricity target for 2030.

Article 12

- We believe a SEM Committee decision is required as soon as possible on the meaning of "subject to existing contracts concluded" at the time of the July 4th 2019 date which defines what are the last generators which receive Priority Dispatch - we believe this should refer to generator units which can become active under a contract concluded before 4 July 2019 including a REFIT/ROCs letter of offer or a corporate PPA.

- We believe a SEM Committee decision is required as soon as possible on the meaning of "significant modifications" in relation to a power generating facility which may result in the loss of Priority Dispatch for existing units. We also believe clear processes and transparency is needed on behalf of the System Operators as to when and why new connection agreements are "required" as per Article 12.

- We believe substantial engagement is required amongst industry, the Regulatory Authorities, System Operators and SEMO to understand how non-priority dispatch renewables will participate in the market, how settlement will work, and what market systems will be utilised in order to dispatch these units. In particular:
    - We strongly recommend the rules for bid-offer acceptance classification require further review, consultation, and impact assessment against different classes of generator, and ultimately appropriate governance of the rules.
    - We also strongly recommend the rules for submission of FPNs for all classes of generation requires further consultation, and those rules impact assessed against different classes of generation.

Article 13

- It is our strong position that constraint of renewable generation which occurs on the power system today is a form of non-market based redispatch and therefore should be fully compensated up to the value of the unit's financial support.
- While we agree with the RAs' interpretation of the level of compensation to which curtailed generators should be entitled described in the final paragraph of page 47 of the Consultation Paper, we strongly disagree with the RAs' interpretation of what is meant by compensation being "unjustifiably high". We believe that the RAs have adopted an incorrect and unlawful test and, as a consequence, none of the options set out in the Consultation Paper can be lawfully implemented.
- It is essential that any generators that receive revenues for redispatch in Ireland and are in receipt of a PSO levy payment are not then penalised for the receipt of these revenues under R factor reconciliation calculation.
- Under Article 13, a non-market participant renewable generator (i.e. de-minimis generator) which is subject to redispatch is due equivalent compensation to a participant generator. A separate compensation process could be designed and rules around FPNs and the deemed prices at which such generators are dispatched will need development.

Lastly, we would like to re-emphasise that the implementation of these Articles will play a large role in the timely delivery of 70% renewable electricity in Ireland and in meeting Northern Ireland's future renewable energy targets. Placing incentives on system operators to minimise constraint and curtailment, through the lawful implementation of Article 13, will reduce investment risk in

Ireland and Northern Ireland and lead to the most cost-effective method of meeting 2030 renewable targets.

We believe continuous engagement between the Regulatory Authorities, System Operators, SEMO, and industry will be critical to implementing Article 12 and Article 13 as soon as possible. We would be grateful for the opportunity to discuss our consultation response with the SEM Committee and to work collaboratively on the next steps.

Appendix A. Responses to Questions posed in the Consultation paper

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

Response:

IWEA and NIRIG agree with the scheduling and dispatch process outlined in Figure 3 (Page 15) of the consultation that constraint and curtailment are considered redispatch. IWEA and NIRIG agree that curtailment is considered non-market redispatch and strongly believe that constraint is also non-market redispatch.

IWEA and NIRIG can see no basis for the assertion in the consultation that constraint action can be considered as market based redispatch. Units that are subject to constraint actions are not chosen with reference to any submitted prices or to the supply/demand balance but solely due to local system limitations.

On Page 13 (last paragraph) the Regulatory Authorities state that "*The RAs are of the view that in the case of the application constraints, as these take into account of Commercial and Technical Offer Data submitted by Participants to minimise the cost of diverging from PNs, this is a form of market based redispatched*". However, the existing market systems do not consider TOD or COD from wind or solar generation. Table 3 of the consultation paper confirms that wind and solar generators "may submit Physical Notification (PN) but this is not currently used in the scheduling and dispatch process by the TSOs." Therefore, following the arguments put forward in the consultation paper itself, it cannot be interpreted that constraint actions for wind generation could be considered anything other than non-market based redispatch.

There may be the misconception that the TSOs use a price of €0/MWh when constraining units in the balancing mechanism. However, this only applies to firm capacity, with the imbalance price being used for non-firm capacity. Furthermore, this is a price deemed by the Trading & Settlement Code, not a market price submitted by a participant and, as a result, this cannot be market based redispatch.

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*

Response:

IWEA and NIRIG support the suggestion of the Regulatory Authorities on the first point in relation to receiving commission programmes; however, IWEA and NIRIG question why this criterion should be limited to the TSOs and not include distribution connections? We would also challenge whether every project is treated equally and receives a commissioning programme from the System Operators. In our experience, the process for receiving commissioning programmes varies considerably project to project and System Operator to System Operator.

For the very detailed reasons set out in section 4.2, IWEA and NIRIG do not support that those projects '*eligible to be processed to receive a valid connection offer*' should qualify priority dispatch as a 'contract concluded before 4 July 2019'.

In November 2019, IWEA submitted a position paper[20] to the Regulatory Authorities outlining that our preferred position was point 3 - "*Where a unit becomes active under a contract concluded before 4 July 2019 including a REFIT letter of offer or PPA*".

[20] IWEA Position Paper on Priority Dispatch and Compensation for Constraint and Curtailment, arising from EU Regulation 2019/943 - https://iwea.com/images/files/20191115-iwea-position-paper-on-priority-dispatch-and-compensation-for-constraint-and-curtailment.pdf

IWEA and NIRIG remain convinced that it is critical this categorisation should be supported by the Regulatory Authorities as it has a direct impact on many projects which have energised since 4 July 2019, or a nearing completion of construction.

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 and NIRIG'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 wind farm that can demonstrate evidence of a route to market, such as a REFIT or ROCs Letter of Offer or a CPPA before 4 July 2019.

Developers that 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, a 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.

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

Response:

IWEA and NIRIG agree with the RAs in this respect, but such units must be able to submit Commercial Offer Data such that any redispatching will also be treated like any other unit.

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.*

Response:

IWEA and NIRIG would begin by wishing to clarify that in Question 4 the difference between traded and metered volume would be settled at the imbalance price and not the entire FPN volume as the question appears to imply.

As described in detail in section 4.1, wind units which are out-of-support, or which operate under future renewable subsidy schemes such as the RESS scheme, will not wish to sell at sub-zero prices in the ex-ante markets and would only wish to spill into the balancing market where price was above zero (or have incremental offers greater or equal to €0/MWh accepted), as to do otherwise would force them to lose money.

It is imperative that a non-priority dispatch renewables unit category exists before the first non-priority dispatch renewable unit begins operating in the market, and that the market mechanism required of Article 12 and 13, which allows participation in the market, or an acceptable RA proposed equivalent that achieves the same in the interim or long term, is in place prior to implementing this element of Article 12. As outlined in Section 4.1, the Wind Dispatch Tool appears to be the best system tool in place to achieve this outcome based on the existing options available. Existing units should remain priority dispatch until they choose to become non-priority dispatch units which is unlikely to occur until a market mechanism is in place. New non-priority dispatch units, as covered under Question 2, should automatically fall into the non-priority dispatch renewables unit category.

As discussed in detail in Section 3 and 4.1 of this response, along with further details given in Appendix B, the meaning of the FPN for controllable non-priority dispatch renewables should also be a matter of consideration. Under Article 6 (1), Balancing Market design should allow for non-discrimination between different market participant types, *"taking account of…the different technical capabilities of generation sources"*. Forcing wind units to submit FPNs on a like-for-like basis with conventional technical characteristics does not meet this high-level requirement of the Regulation and requires deeper consideration.

Consultation Question 4 (continued): *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.*

Response:

We recommend that the TSOs would use participants FPNs, which are likely to reflect the likely output of the wind farm more accurately. Units should not be subject to an information imbalance charge – were it introduced – resulting from a difference in the output of a wind farm forecast by the participant and TSO. We believe substantial engagement is required following the consultation amongst industry, the Regulatory Authorities, System Operators and SEMO, to understand how non-priority dispatch renewables will participate in the market, how settlement will work, and what market systems will be utilised in order to dispatch these units. We have outlined fundamental questions which need to be answered and clarifications which need to be provided in Section 3 and Appendix B of this report outlining our concerns on this topic.

Consultation Question 4 (continued): *As an alternative or as a possible interim measure, taking account of the zero marginal cost nature of non-dispatchable but controllable generation in the market today, i.e. wind, solar, units no longer eligible for priority dispatch could be scheduled to their availability as per the process today on the assumption that this reflects economic dispatch in any case, but where there is excessive generation on the system such units would be subject to energy balancing prior to any priority dispatch units.*

Response:

IWEA and NIRIG do not believe this is an acceptable solution as there will be a difference between out-of-support renewable units, for whom this could broadly be used, (though noting that they will incur some costs by reducing output and being off load) and units under the RESS scheme which will, where the ex-ante market price is less than €0/MWh, lose their CFD benefit and be forced to incur a loss if the resulting imbalance price is less than €0/MWh for the delivered energy.

Non-priority dispatch renewables which are sensitive to market prices, i.e. not on a fixed price contract, need to be able to be able to choose not to be dispatched through submission of a suitable FPN of zero. Subsequently, this brings the follow-on question as to whether participation in the Balancing Market (with an offered INC, simple and/or complex) is mandatory.

As discussed earlier in the response, most Priority Dispatch renewables which are price sensitive, such as out-of-support merchant generation or generation subsidised by ROCs if the day-ahead price falls below “negative ROC”, will also neither want to take an ex-ante position nor be forced to run thereafter. These units must have the option of foregoing priority dispatch as per Article 12.

Furthermore, as per our question in Section 3 and Appendix B, we believe a key question which must be answered is can variable Priority Dispatch generators have an FPN other than their Availability respected?

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

Response:

There are two considerations at play here.

The first involves non-dispatchable non-controllable units (which used to be classed as "Autonomous" under the SEM market design). These can comprise both renewable and non-renewable generators who, under legacy Grid Code rules, were not required to be dispatchable. All non-renewable generators in this category are non-market participants.

As these generators have long-term derogations in terms of ability to respond to dispatch instructions, IWEA and NIRIG are of the view that the concept of dispatch – and whether they have priority dispatch in the context of generation, HE CHP and renewables – is moot. They are allowed to run to their own schedule at their discretion to the limits of their connection offer, just as non-dispatchable demand is allowed to consume. Articles 12 and 13 do not apply, and no change is required to these generators whether they are market participants or not.

However, this topic does raise the issue of controllable, non-participant generators, i.e. "de minimis" generation. Within the context of non-market based redispatch, it is difficult to argue that non-market participants who are redispatched do not qualify for the compensation protections envisaged under Article 13. In the absence of this being raised in the consultation paper, IWEA and NIRIG believe it is premature to propose solutions, other than to set out the following two principles:

- Under Article 13, a non-market participant renewable generator which is dispatched down is due equivalent compensation to a participant generator;
- A separate compensation process could be designed. Rules around FPNs and the deemed prices at which such generators are dispatched will need development.

The first bulleted principle is important to address, given the amount of probable de minimis participants in the upcoming RESS auction.

Consultation Question 6: *Do you agree with the RA's interpretation that new generators which are no longer eligible for priority dispatch (both dispatchable and non-dispatchable but controllable) will be subject to energy balancing actions by the TSOs, considered in dispatch economically and settled like any other instance of balancing energy?*

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

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?*

Combined response to Questions 6-8:

For all of the reasons outlined in Section 4.1, units that currently have priority dispatch, which are controllable and are either dispatchable or non-dispatchable, should in future have the option, but not the obligation, to forego priority dispatch. If the option to forego priority dispatch is chosen, these units should have the same responsibilities and opportunities in the balancing market as other units which are currently non-priority dispatch.

If opting to forego priority dispatch such units should be obligated to submit both COD and TOD, with the units choosing whether to submit simple or complex commercial offer data and being settled for redispatch from their PNs in the same way as any other unit, noting that the PNs may have a different technical form to conventional generation to respect the technical characteristics of the generator pursuant to the non-discrimination required under Article 6 (1).

For these units, the concept of rule sets on bid ranking and tie breaking will cease to exist as they will be treated like any other for energy balancing purposes as per B.2.2.4 (f) of the SEMOpx Operating Instructions. Specifically, the system operator should be able to dispatch all such units to achieve their requirements in the most optimal fashion, regardless of fuel type.

Where non-priority dispatch renewable units are able to fairly reflect the cost of their lost generation through simple bids and offers as part of their COD and TOD, IWEA and NIRIG believe that they should be dispatched on a market basis like any other units. Furthermore, as such units would be treated like all others, the tie-break will cease to apply, and the system operator should dispatch such units in the fashion most suited to the system at that time.

As described in detail in Section 3 and Appendix B, we believe further detailed considerations need to be made by the RAs when implementing these changes, such as:

- When several bid-offer acceptances are happening simultaneously, e.g. energy balancing followed by curtailment arising from accommodating conventional must-run generation, it is important that it is clear how the single dispatch down instruction will be classified, if there are to be different rules for compensation for the two different actions (also due to the impact of the classifications on burden sharing of dispatch away from availability).
- Recommendation: The rules for bid-offer acceptance classification require further review, consultation and impact assessment against different classes of generator, and ultimately appropriate governance of the rules.

- We understand energy balancing to be integral to the actions of the TSO adjusting FPNs to achieve a secure, energy balanced system. As generators adjust their FPNs, this impacts the ratios of energy balancing and redispatch required. As PD and non-PD generators are exposed to energy balancing and redispatch differently, this can lead to incentives for FPNs to be adjusted away from ex-ante traded positions. This also goes for must run conventional generation.
- Recommendation: The rules for submission of FPNs for all classes of generation requires further consultation, and those rules impact assessed against different classes of generation.

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

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?*

Combined response to Questions 9 and 13:

IWEA and NIRIG have taken Questions 9 & 13 together here, in that we believe that a single priority dispatch hierarchy is required. As noted throughout our response, we believe that the introduction of a non-priority dispatch category for renewables will substantially decrease the need to redispatch priority dispatch units but that where this is required the hierarchy would as shown on Pages 36 and 37 of the consultation paper, specifically:

- Non-priority dispatch, whether conventional or renewables, would be dispatched down first on a market basis.
- High efficiency Cogeneration / Biomass / Hybrid / Waste to Energy with Priority Dispatch would then be redispatched on a non-market basis to their minimum generation.
- Wind / Solar / Tidal / Hydro with Priority Dispatch would then be dispatched on a non-market basis.
- Interconnector profiles would then be amended.
- Finally, generation where redispatch results in safety issues arising from the operation of hydro generation in flooding situations would be redispatched as a last recourse.

From discussions with the RAs and TSOs following the publication of the consultation, it is evident that further consultation and consideration on the priority dispatch hierarchy is required.

We note with concern the term "SNSP restrictions" being included in the initial priority dispatch hierarchy on page 34. The paper provides no detail as to what this means with respect to how generation units would be dispatched; however, any implementation of the SNSP limit into ex-ante market scheduling would be in breach of several pieces of legislations relating to market transparency and technology discrimination. We look forward to engaging with the RAs on this topic in future consultations and discussions.

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

Response:

IWEA and NIRIG members have not raised any demonstration projects which may be suitable for this priority dispatch eligibility.

Consultation Question 11: *The RAs' interpretation of the Regulation is that where a new connection agreement is required or where the generation capacity of a unit is increased, a unit will no longer be eligible for priority dispatch.*

The RAs also propose that units should be able to make a choice on whether they wish to retain their priority dispatch status or not. Feedback is requested on this proposal.

Response:

Article 12 envisages loss of priority dispatch where there is a significant modification to a power-generation facility, which shall be deemed to be the case where a new connection agreement "is required". For the detailed reasoning set out in Section 4.3, the term "significant modification" needs careful consideration, as it may lead to adverse consequences for issues such co-location of new renewables development with existing generation.

It is IWEA and NIRIG'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 to a metered Generator Unit (in SEM terminology) that has required a new connection offer. If a new connection agreement is entered into for policy reasons or convenience, but the relevant modification could have been affected by amending the existing connection agreement, then it necessarily follows that a new connection agreement is not required. Article 12 only requires that there is significant modification to a power-generation facility where a new connection agreement is required, not when a new connection agreement is entered into for convenience but the modification could have been implemented without the new agreement.

IWEA and NIRIG would also like to highlight that there are currently a number of projects with modifications in train. Some of these projects have open ECP-1 connection offers for REFIT extensions, while other modifications are ongoing and required in advance of RESS bids, therefore it would be very beneficial if this point around modifications could be clarified as a high priority following this consultation as there are several projects delaying beneficial modifications as a result of the lack of clarity on this point.

Loss of priority dispatch in those circumstances would have serious consequences for any project-financed asset. It is IWEA and NIRIG's position that the interpretation of "significant modification" should not inadvertently prevent efficient forms of further renewable development where possible to do so.We believe clear processes and transparency is needed on behalf of the System Operators as to when and why new connection agreements are "required" as per Article 12.

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

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

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

Combined response to Questions 12, 14 and 15:

IWEA and NIRIG would like to direct the SEM Committee to Section 5 of this report for our detailed views and positions on Article 13 of the Electricity Regulation, and the proposals contained within this consultation.

It is our strong position that constraint of renewable generation which occurs on the power system today is a form of non-market based redispatch and therefore should be fully compensated up to the value of the unit's financial support. Quantifying constraint as non-market based redispatch is supported by several of the SEM Committee's own arguments in the consultation paper.

While we agree with the RAs' interpretation of the level of compensation to which curtailed generators should be entitled described in the final paragraph of page 47 of the Consultation Paper, we strongly disagree with the RAs' interpretation of what is meant by compensation being "unjustifiably high" for a number of reasons set out in section 5.2. We believe that the RAs have adopted an incorrect and unlawful test and, as a consequence, none of the options set out in the Consultation Paper can be lawfully implemented.

In summary, our views on the options are that:

- Option 1 completely disregards Article 13 of the Electricity Regulation and does not come close to being a lawful implementation of Article 13.

- IWEA and NIRIG support all efforts by the System Operators and Regulatory Authorities to minimise non-market based redispatch, and to increase SNSP levels. We believe the best incentive which can be placed upon the System Operators to do so, is to implement Article 13 in full and place the risk of non-market based redispatch with the party whom is best able to manage it. This would incentivise the System Operators to minimise constraint and curtailment, which in turn will maximise the efficiency of the renewables on the power system - this is the purpose of Article 13. Options 2 - 5 fall short of fully implementing Article 13 by placing a cap on the level of compensation provided relating to either SNSP, overall curtailment levels, or per MWh of curtailed energy. All four options do not meet the legal requirements of Article 13, and these options could only be utilised if compensation to the generator is 'unjustifiably high' - which it would not be in any of these situations.
- Article 13 (2) clearly sets out that market based mechanisms for redispatch are preferable. IWEA and NIRIG would be willing to engage further with the RAs and system operators on how a market based mechanism for redispatch might be developed, as suggested in Option 6; however, any implementation of such a system would likely be impossible until the second half of this decade at best, and any discussions on how such a system might develop should only occur in parallel with the full implementation of Article 13 which requires full compensation to be provided for non-market redispatch as it exists from 1st January 2020. The development of any such market based mechanism for redispatch must include substantial engagement and consultation with industry prior to its development.
- In relation to Option 7, IWEA and NIRIG welcome any methods that the TSOs can implement to reduce the volume of dispatch down, now and in future. The developments on the Ireland and Northern Ireland power system to increase SNSP in recent years have to be commended as being exceptional, and we believe the TSOs can continue to increase the SNSP limit to dramatically reduce curtailment out to 2030. However, again we reiterate that Option 7 does not meet the lawful implementation of the Electricity Regulation required under Article 13.

Appendix B. Implementation Detail and Principles

B.1. Generation declarations need to be appropriate for windfarms (including on an interim basis if required)

- Either on an interim or enduring basis, care needs to be taken before assuming the application of either the Wind Dispatch Tool or EDIL, in conjunction with the conventional generator FPN process, (neither without adjustment) is appropriate. The Wind Dispatch Tool is better suited to wind generation in terms of its automated nature, amongst other advantages outlined in the main body of the response, but there is no process to accept FPNs which is a key requirement for renewables seeking to avoid running below cost (avoiding negative prices). EDIL is exceptionally manual and would require a significant capital investment for new systems for many renewable operators. While it does integrate with the receipt of FPNs, those FPNs may lead to a generator declaring below its ability to generate, leading to a procedural "self-curtailment" that it would otherwise prefer to avoid, e.g. a declaration to run to available power, rather than to a specific MW level.
    - It is likely that at a minimum some alteration to either the Wind Dispatch Tool or EDIL would be required to become fit-for-purpose.
- Can variable Priority Dispatch generators have an FPN other than their Availability respected?
- As will be discussed below, when FPNs deviate from ex ante traded positions, they can impact what is considered dispatch (energy actions) or redispatch (constraint/curtailment) in real-time activities. Will there be any rules – non-discriminatorily applied – regulating the relationship of FPNs to the ex-ante traded positions?

B.2. Dispatch and redispatch need to be clearly proceduralised, given the importance of delivered energy to renewable generators

- A precise definition of energy balancing is required. From a market perspective this is fairly clear - has the correct amount of demand achieved a trade in the ex-ante markets? However, in real-time in dispatch, this becomes more muddied. Priority dispatch generators will be given an FPN even if they have not achieved an ex ante position. Conventional generators may require FPNs higher than their traded volumes in order for the FPN to be technically feasible – particularly during times of curtailment. There are several situations where the market may be balanced (Generator Trades = Supplier's Demand Purchases), but the sum of all the accepted FPNs from the TSO may be long (FPNs > Real-Time Demand).

  - New non-priority dispatch renewables are subject to energy balancing first. They share curtailment with legacy priority dispatch plant. FPNs that diverge from the associated ex-ante traded position will change the level of perceived energy balancing required relative to curtailment.
  - For the first example, assume only wind is in the ex-ante markets. If 3000MW of wind have FPNs relative to 3000MW of demand, and wind needs to be curtailed to 2000MW, that is clearly curtailment that should be shared pro-rata between new and old windfarms. However, if in a different example there are 1000MW of conventional FPNs (being a sufficient level for secure dispatch) and there are still 3000MW of wind FPNs, the 1000MW of wind to be turned down now may be assessed in real time as an energy imbalance. New renewables would take the dispatch down risk.
    - In this latter example, the 1000MW of conventional generation may have arisen either because they secured an ex-ante trade, or they have an FPN higher than their traded position in order to provide technically feasible FPNs to the TSO. The 3000MW wind may also have either secured an ex-ante trade of 3000MW, or may have FPNs (either submitted, or deemed at the available energy) greater than their traded position as well.

- A precise definition of curtailment is required. The definition of curtailment goes back to SEM -13-010.[21] That definition does not adequately differentiate between energy balancing and curtailment. For example, where wind FPNs are far in excess of the SNSP limit, and the TSO dispatches down to the SNSP level, all of that is considered curtailment today and is settled as such.
- Will non-priority dispatch renewables have their energy balancing from their ex-ante positions respected like any other conventional generator? In other words, even if there is more wind than demand, if a wind farm with an achieved ex-ante traded position is dispatched below that volume, will it pay its DEC for any firm traded volume?

[21] SEM-13-010 - https://www.semcommittee.com/sites/semcommittee.com/files/media-files/SEM-13-010%20Final%20Decision%20-%20Treatment%20of%20Curtailment%20in%20Tie-break%20Situations.pdf

B.3. Classification rules for dispatch need to be clearly defined, and aligned with the dispatch rules

- At this moment in time, the judge of what is an energy action (dispatch) and non-energy action (redispatch) are the flagging and tagging principles in the Appendix N of the Trading & Settlement Code. Downwards redispatch of wind farms during a curtailment event, in contrast, is identified by the form of the dispatch instruction sent to the individual wind farms, whether it incorporates an element of "energy balancing" or not. These flagging and tagging principles are proceduralised into detailed equations in a non-Trading & Settlement Code document. They currently might not match up with dispatch classification of curtailment. If the dispatch process decided in real-time that the dispatch down of wind was "energy balancing", but the action was identified subsequently as redispatch or the instruction was identified procedurally as curtailment, the compensation may be different under the Trading & Settlement Code than what would have been reasonably expected based on the sharing of the dispatch between new and old renewables. The 'Methodology for System Operator and Non-Marginal Flagging' and the identification of the type of action by the TSO are key processes that need to be brought into scope of future implementation considerations relating to this consultation. For the avoidance of doubt this is not intended to be a route-and-branch re-examination of Flagging and Tagging, merely to ensure that the wholesale market receives consistent information, i.e. dispatch actions are not inadvertently settled as redispatch and vice versa.

B.4. Settlement detail needs to be at least provided with principles, so it does not undermine policy

- There are several factors which will have a determination on where and how any changes to settlement rules are implemented. These may inform the necessity to leverage the existing market algebra or may not.
    - Is there a legal requirement to make payments retrospective to 1st January 2020?
    - Is a generator required to be participating in the market and have an ex-ante position to qualify for available compensation for non-market based redispatch?
    - How long will a change to the central market systems take relative to other potential non-market solutions?
- Where FPNs can deviate from ex-ante market traded positions, this is dealt with in settlement by the calculation of a Biased Quantity in the Trading & Settlement Code, which essentially

limits the amount of energy that is settled, for example, as curtailment or with an INC or DEC. New renewables will frequently face energy balancing, followed by curtailment, in a single dispatch down instruction. **If there is a concurrent Biased Quantity in play at the time of such instruction, will the Biased Quantity preferentially impact the energy balancing or curtailment calculation, or will the Biased Quantity be assigned pro-rata. (Note that this question may be moot if the calculation of support is carried out outside of the Trading & Settlement Code).**

- Example: A windfarm has a trade of 5MW, it is available for 15MW, and has an FPN at 15MW. (This assumes that the FPN can be higher than the ex-ante trade, which is related to the FPN queries in Appendix B.1) It is energy balanced downwards to 9MW and subsequently curtailed downwards again to 5MW. There is 6MW of energy balancing and 4 MW of curtailment. Does the allocation of the 5MW of trade to an action make a difference for settlement (it definitely does for market based dispatch and redispatch)? What are the allocation rules for that trade? This is another way of asking where is the biased quantity of 10MW assigned in settlement – to the market based action, or to the non-energy action?

The four categories listed above, along with the examples and questions posed are clear reasons why IWEA and NIRIG are strongly of the view that decisions on key items within Article 12 and Article 13 cannot be progressed without further detailed discussions and consultations.

A roadmap should be published by the SEM Committee as to how and when clarifications on such issues can be provided.

Appendix C. Analysis of Curtailment and Energy Balancing in 2030 Scenarios

C.1. Background to analysis

IWEA and NIRIG requested MullanGrid to undertake 2030 curtailment analysis relating to the proposals in the SEM Committee consultation on Article 12 and Article 13 of the Electricity Regulation. MullanGrid's 2030 base case curtailment analysis estimates **8% total all-island wind curtailment** consisting of **4% due to energy balancing** and the other **4% due to system curtailment**. It should be noted that this analysis does not consider constraints which will increase the total all-island dispatch down levels beyond 8%.

MullanGrid's 2030 base case curtailment analysis is based on the following main assumptions:

- 70% RES-E target achieved
- 52TWh All-Island Demand based on median projections in 2019 Generation Capacity Statement
- ROI Wind: 9,528MW consisting of 7,603MW onshore and 1,925MW offshore
- NI Wind: 2,339MW onshore
- ROI Solar: 2,000MW
- NI Solar: 600MW
- Interconnector Export Availability: 80MW on Moyle, and 75% export availability on EWIC (530MW), Greenlink (500MW) and Celtic (700MW).
- SNSP Limit: 90%
- Min Gen: 897MW

C.2. Scenarios

Based on the proposals in the SEM Committee consultation, several scenarios were modelled in terms of 2030 wind curtailment. For the purposes of this response, the results of two scenarios are presented - denoted as 'Scenario 3' and 'Scenario 5' in the following results section. They can be summarised as:

- Scenario 3 - All wind & solar projects which are currently connected and projects which are capable of becoming 'active' through a signed REFIT/Corporate PPA contract are considered "Old" generation and everything beyond that point is considered "New" generation. Note, this scenario relates to point 3 in the SEM Committee paper on the cut-off date for projects to qualify for priority dispatch and is IWEA and NIRIG's preferred position.

- Scenario 5 - All wind & solar projects which have connection offers or are '*eligible to be processed to receive a valid connection offer*' are considered "Old" generation and everything beyond that considered "New" generation. Note, this scenario relates to point 2 in the SEM Committee paper on the cut-off date for projects to qualify for priority dispatch and, as set out in section 4.2 of the response, IWEA and NIRIG do not believe units should qualify for priority dispatch under this criteria.

For all scenarios it is assumed that energy balancing is allocated first to "New" wind and solar, and system curtailment is allocated pro-rata to all renewables. The capacity figures for "Old" and "New" wind and solar generation was determined using MullanGrid's internal database.

C.3. 2030 Energy Balancing and Wind Curtailment Estimates

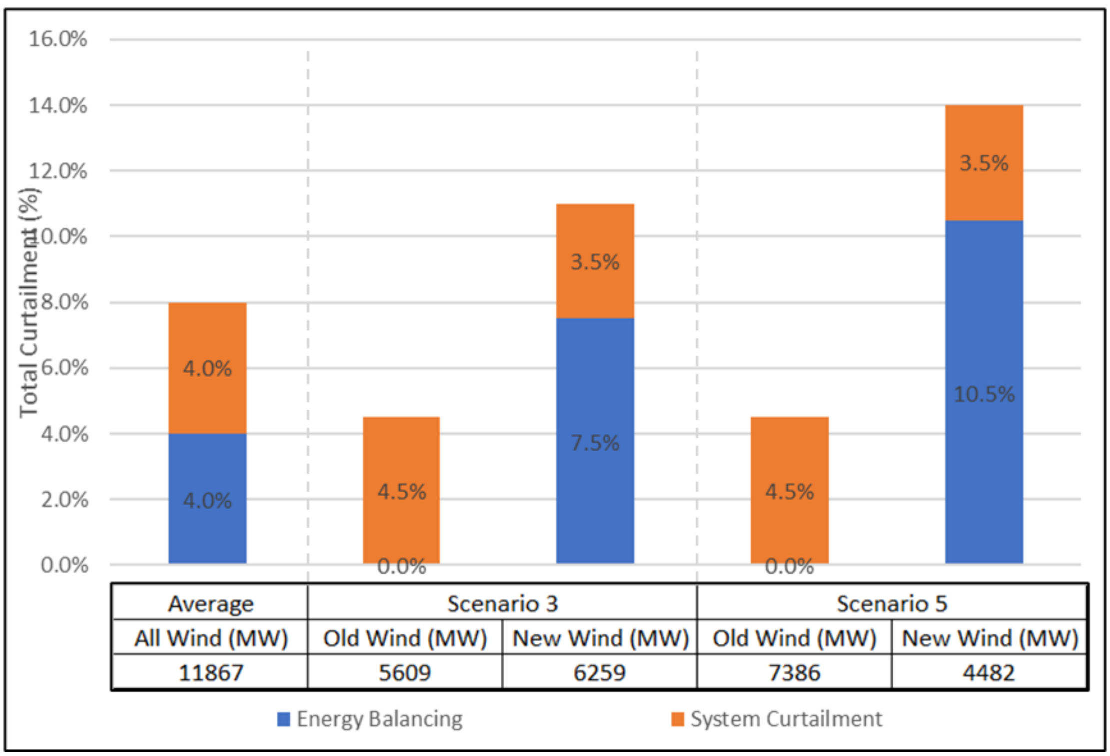

Figure 1: 2030 Wind Curtailment and Energy Balancing Estimates

As shown in Figure 1, the 2030 base case average total wind dispatch down, considering only curtailment and energy balancing, is estimated to be 8% and this consists of 4% energy balancing and 4% system curtailment. The burden of energy balancing and system curtailment is then distributed across the "Old" and "New" categories of wind generation in Scenarios 3 and 5. In both scenarios the overall volume in GWh of curtailment and energy balancing remains the same; however, the percentage varies across scenarios as there are differing capacities of generation in the “Old” and “New” categories in Scenario 3 and 5.

The analysis indicates for all the scenarios that energy balancing is completely absorbed by “New” wind and therefore there is no need to allocate excess energy balancing to “Old” wind. However, the percentage of energy balancing which is absorbed by the “New” wind increases as the capacity of “New” wind category reduces in the scenarios. As a result, there is 3% more energy balancing on the “New” wind category in Scenario 5 because there is less capacity to distribute the burden.

The percentage of system curtailment is higher for “Old” wind compared to “New” wind because at times energy balancing will significantly reduce or turn off the “New” wind. If system curtailment then occurs at times when “New” wind is off because of energy balancing, the only generation left on the system to curtail is the “Old” wind - meaning it sees comparatively higher volumes of curtailment over the course of the year.