WEI and RNI Joint Response to the SEM Committee's Consultation Papers on the Implementation of Articles 12 and 13

Executive Summary

Wind Energy Ireland (WEI) and Renewable NI (RNI) would like to thank the SEM Committee (SEMC) for the opportunity to respond to the Consultation Papers on SEM-21-026 Dispatch, Redispatch and Compensation Pursuant to Regulation (EU) 2019/943 and SEM-21-027 Proposed Decision on Treatment of New Renewable Units in the SEM.

Like the SEMC and Regulatory Authorities (RAs), WEI and RNI members are committed to playing our part in delivering future targets on emissions reduction and renewable energy at the lowest cost to the end consumer. However, we are concerned that the proposals in these Consultation Papers, if implemented, will significantly adversely impact on the ability of the industry to deliver the required investment to enable Irish and Northern Ireland governments to achieve their decarbonisation targets.

Regulation (EU) 2019/943 creates the binding legislative framework for facilitating the necessary levels of investment at least cost to consumers. The proposals set out in this Consultation, which would only serve to increase cost for consumers and threaten national climate ambitions are, in our view, a direct consequence of a proposed departure by the RAs from the express legal requirements of Regulation (EU) 2019/943. To this end WEI and RNI members urge the SEMC to reconsider the proposed interpretation of Regulation (EU) 2019/943 as currently set out in the Consultation Papers.

Building on this point, WEI and RNI members believe that the proposals set out by the SEMC allocate risk to generators that is impossible for our members to manage, meaning that the cost to consumers of developing further renewable capacity will be significantly greater than is necessary. We are also concerned about impacts on the expected performance of existing investments, with inadequate compensation for higher-than-expected constraint and curtailment in SEM, which is contrary to the requirements of the Regulation.

This response document has been structured to provide feedback on the areas of both Consultation Papers SEM-21-026 and SEM-21-027, which are of the highest priority for our members. The overarching principles of our response, to be viewed as an integrated whole, are to ensure:

- That compensation for dispatch down is compensated as required by law under the Clean Energy Package (CEP). We strongly argue that the legal requirements of the CEP need to be implemented in full, specifically the right of all qualifying generation to compensation at the level of financial support for downwards redispatch.
- That when the provisions of Article 13(3) are considered, constraints (in addition to curtailment) should be considered as non-market based redispatch. To ensure fair and even burden sharing, constraints should continue to be applied on a pro-rata basis.

- That existing BCOP is amended to allow non-priority dispatch plant to bid into the market. The BMPCoP was developed in a scenario that did not anticipate dispatchable wind, and in our view, it is not suitable for wind generation in its current form.
- That risks and incentives, primarily around network constraints, curtailment, and firm access to the grid, need to be allocated to the parties best able to manage those risks[1].

We believe that a decision underpinning these core principles would facilitate investment in new renewables at an efficient cost for the end consumer, maintain the viability of RESS-1 and corporate power purchase agreement (CPPA) projects in ROI and the equivalent pipeline of projects in NI, and provide for a sustainable investment environment for existing renewable generators in the SEM.

To deliver on these objectives, we have set out several preferred positions (some outside the scope of the SEMC proposed decision and consultation) in our response. These positions seek to achieve a balance between the fair interests of new investment, in-development projects (under RESS-1, CPPAs and merchant projects in NI for example), and existing renewable generators under the terms of the Regulation. They have key interactions, which centre on the allocation of risk for downward redispatch between new renewable generators and priority dispatch generators, and encompass the following elements:

- The allowed bids and offers for redispatch under licence-obligated bidding principles.
- The determination of what generators are entitled for compensation due to the characteristics of their connection offer (i.e., “firmness”).[2]
- The required trading necessary for priority and non-priority dispatch plant to achieve an energy position.
- The extent to which the above three factors will apply to either market-based (Article 13(2)) or non-market-based (Article 13(7)) compensation mechanisms.

Descoping potential change from, and/or misalignment of, one or more of the above elements can lead to an unworkable, non-sustainable, or non-investible market design, undermining the rights of some or all renewable generators under the Regulation, and negatively impacting non-renewable generators, System Operators, and consumers alike. Ambiguity on such elements renders the SEMC proposals non-assessable, and therefore not supportable without clarification on matters upon

[1] WEI and RNI will be writing to the RAs separately on the required principles of a new Firm Access Policy, and the need for urgent engagement on this topic in the coming weeks.

[2] In relation to connection offers, our members feel that it is imperative that SEMC finalises this consultation as quickly as possible to ensure that there are no delays to the ECP process due to uncertainty that this consultation has introduced to the ECP2.1 constraints analysis that is currently underway by EirGrid. Further detail on the uncertainty that the SEMC consultation has resulted in for the ECP2.1 constraints analysis is outlined in section 4.1.

which the SEMC have not directly consulted, and therefore we can have no confidence will be delivered through further SEMC processes.

We urge the SEMC to ensure that their next step in this process considers all relevant factors (including where necessary, matters under the separate vires of the RAs) on a holistic level. We also request that the Regulatory Authorities refrain from making any decisions on matters in Regulation (EU) 2019/943 in respect of which the Regulatory Authorities have a discretion, until the threshold legal requirements of Regulation (EU) 2019/943, in respect of which the Regulatory Authorities do not have any discretion, are agreed.

In summary, the overarching principles of the WEI and RNI response are to ensure:

1. **That compensation for dispatch down is compensated as required by law under the Clean Energy Package (CEP). We strongly argue that the legal requirements of the CEP need to be implemented in full, specifically the right of all qualifying generation to compensation at the level of financial support for downwards redispatch.**
2. **That when the provisions of Article 13(3) are considered, constraints (in addition to curtailment) should be considered as non-market based redispatch. To ensure fair and even burden sharing, constraints should continue to be applied on a pro-rata basis.**
3. **That the existing BCOP is amended to allow non-priority dispatch plant to bid into the market. The BMPCoP was developed in a scenario that did not anticipate dispatchable wind, and in our view, it is not suitable for wind generation in its current form.**
4. **That risks and incentives, primarily around network constraints, curtailment, and firm access to the grid, need to be allocated to the parties best able to manage those risks.**

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1. Introduction

Wind Energy Ireland (WEI) and Renewable NI (RNI) welcome the opportunity to respond to the Consultation Papers on SEM-21-026 Dispatch, Redispatch and Compensation Pursuant to Regulation (EU) 2019/943 and SEM-21-027 Proposed Decision on Treatment of New Renewable Units in SEM.

WEI is the largest 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. RNI is a collaboration between Wind Energy Ireland and RenewableUK and is the voice of the renewable electricity industry in Northern Ireland. Together we represent a large majority of the renewable industry and supply chain on the island.

WEI and RNI have been active in discussions with the Regulatory Authorities (RAs), the Single Electricity Market Operator (SEMO) and the System Operators (SOs) on this topic for several years. We welcome the decision to further 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.

This response has been structured to provide feedback on the areas of both consultation papers SEM-21-026 and SEM-21-027, which we feel are of the highest priority.

- We have set out a background to our understanding of the Electricity Regulation in Section 2.
- Section 3 and Section 4 outline the main issues we believe are important for implementing Article 12 and Article 13 respectively, and our main considerations in the response.
- We address the specific proposals in the Consultation Papers in Section 5 and Section 6.
- We recap on the overarching principles of our consultation response in Section 7.
- Appendix 1 includes correspondence between WEI, RNI and the RAs during the consultation.

2. Background and Context

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.[3] 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.[4] 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 this Consultation is occurring in mid-2021, and that any implementation of the Regulation would appear to be some time away. We strongly recommend that the RAs 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 two years prior to the Consultation, and the Clean Energy Package has been expected and in various stages of drafting since 2015, it is imperative that no further time is lost and a clear roadmap to implementation of Article 12 and 13 is provided. This is needed to give clarity to SEMO, the SOs 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 across the island. Any further uncertainty on a live Regulation in a live market creates material commercial uncertainty and risk for all parties involved and presents significant challenges to governments in both Ireland and Northern Ireland in achieving decarbonisation targets.

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

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

3. 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 section sets out WEI and RNI's understanding of Article 12 and considerations which we believe should be considered in any future decisions or consultations on the below topics.

3.1 Treatment of Non-Priority Dispatch Renewable Generation

The principal 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 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) scheme in ROI. 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.

It is important to emphasise that until systems are put in place so that renewable units can turn off when not dispatched in the ex-ante markets, just as thermal units do today, then such units are subject to a risk beyond their control. As the number of units under RESS and CPPAs grows, and the number of units under REFIT and ROCs decreases as units exit the schemes, this will become still greater a risk to new and old projects and more important for the market as a whole.

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. WEI and RNI 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 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. WEI and RNI 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. WEI and RNI recommend the Wind Dispatch Tool is amended, or a purpose built suitable alternative system is developed, to allow this to happen.

WEI and RNI have been informed that amending the market systems to do so will require non-trivial systems changes. However, WEI and RNI 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, WEI and RNI members believe that facilitating the access of non-priority dispatch units to become price makers in the SEM, will mean those units 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.

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"[5], rather than a declaration of "I wish to run the following minute-by-minute forecast of my available wind output". Non-priority dispatch

[5] Of course, a generator may wish to nominate a delivery schedule less than its full availability.

units which are obligated to submit both COD and TOD, should have the right to choose 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).

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 dispatching 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.

One final consideration in this discussion is the risk of existing dispatchable plant submitting FPN's which deviate from their ex-ante traded position. For example, if conventional generators submit FPN's that are 200MW more than their ex-ante traded position, this could result in an additional 200MW dispatch down of renewables generation being classified as energy balancing rather than re-dispatch with the burden of this dispatch down being borne first by new non-priority dispatch renewables. (i.e., deviations between conventional ex ante trades and FPN's are grandfathered between PD and non-PD renewables). Exposure to this risk would increase volatility and revenue uncertainties and would be counter to the intent of the Regulation.

4. 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.

4.1 Market versus Non-Market Based Redispatch

i. RA Proposal & Associated Implications

SEM-21-026 states that the Regulatory Authorities are of the view that constraints as applied to all non-priority dispatch units are a form of market based redispatch. WEI and RNI can see no basis for the assertion 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. Furthermore, the existing market systems do not consider TOD or COD from wind or solar generation.

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.

We understand that the RAs are of the view that Article 13(3) which ties their hands insofar as it implies that constraints need to be market-based where possible. We further understand that the RAs have advised WEI and RNI that if the industry can come up with a legitimate argument, which is compliant with Article 13, as to why constraints should be pro-rata / non-market based in future, as part of this Consultation, then they would consider it.

We acknowledge that Article 13 specifies the SO should select market participants for redispatch based on market-based criteria, i.e., those providers should compete on price in order to be selected in a merit order to be dispatched to resolve system security issues. This is set out in Article 13(1) and Article 13(2). If, however, one of a number of criteria are met, the SO may utilise "non-market" based resources to resolve system security issues. This allows the SO to distort unfettered price-based competition in the market when selecting resources to resolve the system constraint.

These criteria are set out in Article 13(3), reproduced in its entirety below (emphasis added).

"3. Non-market-based redispatching of generation, energy storage and demand response may only be used where:
(a) no market-based alternative is available;

(b) all available market-based resources have been used;
(c) the number of available power generating, energy storage or demand response facilities is too low to ensure effective competition in the area where suitable facilities for the provision of the service are located; or
(d) the current grid situation leads to congestion in such a regular and predictable way that market-based redispatching would lead to regular strategic bidding which would increase the level of internal congestion and the Member State concerned either has adopted an action plan to address this congestion or ensures that minimum available capacity for cross-zonal trade is in accordance with Article 16(8).

The SEM-21-027 reiterates the SEMC determination that constraint and curtailment are forms of redispatch under the Regulation. They have determined, however, that constraint for new renewables without Priority Dispatch should be market-based. This proposal was made without consideration of Article 13(3) above and was justified on the basis of Article 13(1) and Article 13(2). The SEMC concludes that: *"…it is clear that Article 13(1) and 13(2) envisage a market-based mechanism for applying constraints to all unit types as far as possible". The SEMC also expressly quoted that "resources that are redispatched shall be selected from among generating facilities, energy storage or demand response using market-based mechanisms and **shall be financially compensated**"* (emphasis added here).

WEI and RNI members believe that this conclusion, based on Article 13(1) and Article 13(2), is problematic under three criteria.

ii. Arguments for Non-Market Based Redispatch

1. <u>The SEM Committee have Previously Decided Implicitly that the Conditions of Article 13(3)(c) Applies in the SEM</u>

In the I-SEM Market Power Mitigation Decision Paper (SEM-16-024), the SEM Committee mandated short-run marginal cost complex bid and offers to apply for all redispatch in the I-SEM. The explicit quote in the decision is given below (again, emphasis added):

*"As a result of non-energy actions, units that would normally not be dispatched are scheduled to run by the TSOs. This could be due to a multitude of reasons such as network constraints. As **there effectively exists no market under these conditions** the generator can effectively act as a monopoly at times. The SEM Committee sees this as a considerable risk to consumers and believes that imposing bidding conditions is appropriate in these circumstances."*

The SEMC have therefore previously determined that there was insufficient competition for constraints in the SEM. The current proposed decision paper neither revisits the rationale behind this original decision nor presents evidence that such market power issues have been resolved. One must conclude that either:

a. the original assertion in SEM-16-024 was incorrect and the rationale for the Bidding Code of Practice (as intended to be amended to the Balancing Market Principles Code of Practice) was flawed, or
b. the assessment that constraints are market-based redispatch for new renewable generation is an error.

2. Compensation should be Paid for All Market-Based Redispatch

Article 13(2) requires generators which are subject to market-based redispatch to be financially compensated.

"2. The resources that are redispatched shall be selected from among generating facilities, energy storage or demand response using market-based mechanisms and shall be financially compensated."

The SEM Energy Trading Arrangements Detailed Design Building Blocks Decision Paper (SEM-15-064) determined the financial treatment of market participants subject to downwards constraints. The compensation arrangements are different for generators with financially firm connection agreements ("firm") and with non-financially firm connection agreements ("non-firm"). It is difficult to quantify either as "financial compensation". They are:

a. Firm generators: "*a generator that is constrained down from its ex-ante position will, providing it has firm access, retain its infra-marginal rent*". It is not apparent that retaining a profit already achieved in the ex-ante market (its inframarginal rent) is a form of financial compensation as envisaged under the Regulation. Indeed, restricting generators to the Bidding Code of Practice bound bids for downward redispatch arguably does not meet the requirement of "market based" at all; and
b. Non-Firm generators: *"Generators with non-firm access should be allowed to trade in the ex-ante markets above their firm access levels. There are liquidity benefits associated with such an approach, but the risks of such trades must lie with the participants undertaking them".* This is a necessary requirement for non-firm generators to be able to be balance responsible. Nevertheless *"…a generator which is constrained down, in its non-firm region, relative to its ex-ante position should be cashed out in the same way as any other generator deviations from ex-ante trades."* It is not possible to claim that requiring generators to buy back at the Imbalance Settlement Price could reasonably be called being "financially compensated".

As these generators are not financially compensated at an adequate free-market level, they have not been subject to market-based redispatch.

3. Treatment of Non-Firm Access Imbalance Adjustments are Contrary to the Electricity Balancing Guideline

The Electricity Balancing Guideline Network Code under Article 49 states that:

"1. Each TSO shall calculate an imbalance adjustment to be applied to the concerned balance responsible parties for each activated balancing energy bid."

This is not facilitated for non-firm access generators in the SEM today. They are responsible for the downward redispatch imbalance volumes arising, further indicating that downward redispatch for constraints is not treated as an EBGL compliant "balancing energy bid". This is further indication that such downward redispatch is non-market based.

To reiterate, for the reasons outlined above, WEI and RNI members strongly believe that constraint of renewable generation is a form of non-market based redispatch and therefore should be fully compensated up to the value of the unit's financial support. We believe that this categorisation is important, to (i) protect the interests of consumers; and (ii) achieve Ireland and Europe's decarbonisation ambitions.

We must emphasise that the proposals of the Regulatory Authorities are not only inconsistent with the correct interpretation of the Regulation but are also incompatible with both (i) protecting consumers (the RAs proposals will cost consumers at least as much if not more than compensating in accordance with the Regulation); and (ii) achieving Ireland's decarbonisation obligations.

Finally, in relation to constraints, and as alluded to in the Executive Summary, it should be noted that EirGrid are currently using pro-rata modelling of constraints as part of their ECP2.2 constraint forecasting, which will be used by financial institutions as part of their modelling of lending requirements. If there is a lack of clarity as to how constraints are determined, this will undermine this work and the signal for investment in new renewables.

4.2 Compensation for Non-Market Based Redispatch

i. Introduction

WEI and RNI members are concerned that the Consultation does not sufficiently engage with much of the content of our response on the previous consultation SEM-20-028. We believe that our views were consistent and backed by compelling legal, policy and economic argument in relation to the intent and proper interpretation of the Regulation. We believe that we presented compelling evidence of the legislative background to the Regulation, the policy intention of the European Commission and the practice in other jurisdictions. While much of this evidence is summarised in the current Consultation, we are concerned that it was not engaged with.

The Consultation correctly defines curtailment as non-market based redispatch. However, WEI and RNI 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 this 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. The threshold point is that Article 13(7) is legally binding and is not a matter in respect of which the SEMC has a discretion. For the reasons set out herein, WEI and RNI believe that the SEMC will ultimately be compelled to comply with the provisions of the Regulation in relation to compensation.

Delaying an inevitable decision to implement these provisions has the potential to result in consumers being charged "on the double", i.e., by failing to provide clarity in advance of a RESS 2 auction, many RESS bidders may choose not to include assumed compensation payments in their bid prices. When this is ultimately enforced, they will receive compensation payments in addition to the higher bid price that would have been calculated excluding compensation allowances.

The Consultation SEM-21-026 refers (at page 37) to Recital 2 of the Regulation which notes that an aim of the Energy Union is to provide final customers with safe, secure, sustainable, competitive, and affordable energy. While it is clear that there is a need to have regard to consumer protection, this does not provide the RAs with any discretion to depart from the express terms of the Regulation, and in particular the provisions with regard to financial compensation under Article 13(7). In fact, Article 13(7) was drafted with those aims in mind and to depart from the plain meaning of the Regulation in this way is counterintuitive to the aims set out in Recital 2 of the Regulation.

WEI and RNI members 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, consequently the proposals set out in the Consultation cannot be lawfully implemented.

We have therefore not responded to the specific proposals within this section of our response, 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 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 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 <u>minimum</u> 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.

Depending on the generator type, the interplay between the operating costs outlined in 13(7)(a) and the net revenues described in 13(7)(b), would likely result in a wide variety of compensation amounts were it not for the stipulation of compensation being 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*". Inclusion of this stipulation ensures that a mechanism exists such that all generator types can be compensated to the level of being financially indifferent to being redispatched. This stipulation within Article 13(7) therefore 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) therefore does not create a cap on compensation, it only creates a floor.

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 methodology for calculating the level of compensation that involves a 'combination' of the two limbs. As such it is not open to the Regulatory Authorities to simply ignore the minimum compensation requirements in any circumstance – it must apply a combination of (a) and (b). For example, if a biomass plant is dispatched down and was compensated for its full foregone revenue (including renewable supports) it would be overcompensated because it would be recovering more than it would have recovered had it generated (since it has saved its fuel cost by not generating).

In this case, Member States are permitted to compensate such a generator using a combination of (a) and (b) to deduct the avoided fuel cost from the lost revenues. Conversely, compensating a plant using only the higher of limbs (a) and (b) may undercompensate a generator, for example where a HE-CHP plant is dispatched down, it may lose energy revenues and also incur costs associated with replacement heat. In this case compensating on the higher of limbs (a) and (b) would undercompensate the generator and the Member State must compensate using a combination of both. In the case of zero marginal cost generation, the higher of limbs (a) and (b) would always be limb (b) and therefore this must be the measure of compensation for such generators. It is not open to the Regulatory Authorities to depart from this.

In all cases, Article 13(7) contains an absolute requirement that (i) a generator that subject to non-market based redispatched is compensated by the system operator; and (ii) that the level of compensation is <u>at least</u> 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.

ii. RA Interpretation of Article 13(7)

In the Consultation Paper SEM-20-028, the RAs reached the proposed conclusion 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 cited 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”; (iv) “specific characteristics in the SEM in relation to system wide curtailment that are not reflected in other EU Member States”; (v) 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 (vi) “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”. This conclusion is maintained in the current Consultation.

However, Article 13(7) contains an objective requirement rather than discretionary power. As such, any regard that the Regulatory Authorities have to the factors mentioned above, or indeed other provisions of the Regulation in deciding whether or not to implement Article 13(7), involves the Regulatory Authorities acting ultra vires by purporting to exercise a power that they do not have. It is clear from the regard had to these considerations that the Regulatory Authorities do not agree with the views of the European Parliament and Council in relation to levels of compensation required to be paid in the event of non-market based redispatch. However, the fact that the Regulatory Authorities may have made a different policy decision to that reflected in the Regulation is not a matter to which the Regulatory Authorities can have regard. The Regulatory Authorities are bound to implement the Regulation whether they agree with it or not.

At page 28 of Consultation Paper SEM-21-026, the Regulatory Authorities indicate they do not believe it is appropriate to compensate priority dispatch units on a different basis to the compensation arrangements in place today. However, the suggestion that the approach to compensation of curtailment in SEM-13-010 is appropriate today is equally unrealistic. This was developed in an entirely different context, against the background of significantly less ambitious decarbonisation measures and, most importantly, in the context of a different legislative regime. This is not a view the Regulatory Authorities are legally entitled to take. The compensation arrangements in place today were determined by the Regulatory Authorities a number of years ago prior to the Electricity Regulation coming into force. Now that the Regulation is in force, those arrangements are binding upon Ireland.

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 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 at 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:

iii. 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.[6] 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.[7] 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 that the RAs have 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.

iv. Literal Interpretation of Article 13(7)

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), or 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*

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

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

the redispatching request". If the compensation equals what would have been received, 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. 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.

v. 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.[8]

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.

vi. 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

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

Regulatory Authority, Commission de Regulation de l'Electricite et du Gaz (CREG) recently interpreted the requirements of Article 13(7) as follows[9]:

> "*Production units which are redispatched downwards are remunerated (compensated according to 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[10]: "*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,[11] 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 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.

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[9] https://www.creg.be/sites/default/files/assets/Publications/Studies/F1987EN.pdf at paragraph 46.

[10] https://www.creg.be/sites/default/files/assets/Publications/Studies/F1987EN.pdf at paragraph 29.

[11] https://www.bmwi.de/Redaktion/EN/Publikationen/Studien/future-redispatch-procurement-in-germany.pdf?__blob=publicationFile&v=2

vii. Legislative history of Article 13(7)

The RAs view 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's Commission 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).[12]

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:…*"[13]. 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 <u>at least</u> be 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*".[14] Given that it is clear that 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 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).

viii. TSO Incentivisation

The Regulatory Authorities make the point in the Consultation that TSO incentivisation "*is the responsibility of each RA in relation to the jurisdictional SONI and EirGrid price controls*".SO

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

incentivisation may not be "the subject of this paper", but it is at the heart of the Clean Energy Package and Article 13(7) of the Regulation in particular. The Regulatory Authorities therefore cannot take their view that it is not their job to incentivise TSOs and therefore can disregard their responsibilities to implement Article 13(7) in a manner that appropriately incentivises investment in transmission, demand response, storage, and cross zonal capacity. The definition of "SEM Matter" under domestic law cannot absolve the Regulatory Authorities of their responsibility to implement Article 13(7) in accordance with its terms.

The importance of appropriate levels of compensation for redispatch to ensuring necessary investments in transmission, demand response, storage, and cross zonal capacity was described by the European Commission[15] as follows: "*In principle, market-based resources should be used first, thus curtailing or redispatching first those generators which offer to do this against market-based compensation. In a second step, where no market-based resources can be used, minimum rules on compensation are foreseen, ensuring compensation based on additional costs or (where this is higher) a high percentage*[16] *of lost revenues. It would mean that network operators would obtain a clear incentive to make an assessment on the basis of costs as to the alternatives available to them to address the underlying network constraints, thereby creating opportunities for more innovative solutions such as storage. The increase in transparency and legal certainty would notably also prevent discrimination against certain technologies (particularly RES E) in curtailment and redispatch decisions*."

4.3 Re-allocation of Risk and Consumer Benefits

One critical point which the Consultation does not discuss in relation to the full implementation of Article 13, is that it will reallocate a significant forecasting risk faced by renewable developers to the System Operator – that of constraint and curtailment.

In WEI and RNI's view this reallocation is welcome as the SOs 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

[15] Commission Staff Working Document Impact Assessment accompanying the document, inter alia, Proposal for a Regulation of the European Parliament and of the Council on the electricity market (recast) SWD(2016) 410 final (Part 3 of 5)

[16] Note that Regulation as enacted the percentage of lost revenues that is required to be compensated is 100%.

Ireland also. This means projects must 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.[17] In relation to constraints, EirGrid's ECP-1 constraint reports project potential constraint levels of between 11-12% in Galway, 26-28% in Mayo[18] and 12-14% in Donegal[19] 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, the SOs recent *Shaping our Electricity Future* report identified the need for grid development in all scenarios analysed across all regions of the country.

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 RESS1 presented a safeguard to provide some support should curtailment exceed 10% for two consecutive years,[20] this does not account for dispatch down as a result of constraints or energy balancing. 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.

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

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[17] 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

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

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

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

Operators by either adjusting the electricity market rules to incentivise solutions, such as through EirGrid's DS3 programme, and its successor 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 SOs and RAs that can manage dispatch down costs. However, it is equally important that the market is sending efficient investment signals to SOs and RAs to invest in the creation of transmission system capacity in regions where renewables can be delivered at the lowest cost to consumers.

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.

Finally, allocating the management of constraint and curtailment risk to the System Operators, will focus action towards addressing the underlying system limitation driving constraint and curtailment actions in a timely manner.

4.4 Consideration of Firm Access Policy

WEI and RNI members consider the definition of Firm Access as an essential policy requirement, accompanying the implementation of Articles 12 and 13. From an ROI perspective, it is required to allow developers to submit RESS bids with confidence and to align with the assumptions that projects have made in the past for RESS/REFIT/CPPA contracted projects to ensure that these projects remain viable. From an NI perspective, it is important that binding certainty is provided for new projects.

We see it as a fundamental part of the approach adopted around firm access that it allocates the risk of delay to achieving targets with the parties (i.e., SOs, RAs and government policy) best placed to manage this risk. Certainty around firm access will ensure that auctions are more successful as unit bids could then exclude contingency for this risk that will otherwise have to be built into bid prices.

Firm Access is a complicated area that requires immediate industry engagement by the System Operators with a focused consultation on the specifics of this. Development of a policy on Firm Access is well overdue and is essential to provide confidence to investors. There has been a lack of policy on firm access for many years and the last projects that received non-binding firm access dates were almost 10 years ago.

It is essential that a separate consultation on firm access policy considers application for (i) existing firm projects, (ii) existing non-firm projects that had firm access date advised, (iii) existing non-firm projects and (iv) future projects, and how firm access is confirmed/communicated for each of these types of projects to be considered. A new policy should also give consideration of other solutions/measures which can help mitigate any delays in ATR completion (i.e., Smart grid solutions including DLR, virtual battery network, power flow control devices, new and emerging long duration storage technologies, and hydrogen).

WEI and RNI will be writing to the RAs separately on the required principles of a new Firm Access Policy, and the need for urgent engagement on this topic in the coming weeks.

4.5 Consideration of the R-factor Calculation for the PSO Levy

Whilst outside the direct scope of this paper, it is important that any revenues for redispatch received by generators in Ireland who 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 be done simply by excluding the CDISCOUNT and CCURL charges from the R factor reconciliation calculation.

4.6 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 CPPAs top-ups.

WEI and RNI believe that these payments should be recovered in a fashion that is fair and equitable to all and which could be implement 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 Article 13 of the Electricity Regulation applies strictly from 1st January 2020, then the compensation would need to be effective from 1st January 2020.

It is our position that where compensation cannot be paid through the existing market systems due, for example, to implementation delays, non-retrospective nature of the Balancing Market system design etc, then a separate compensation process should be devised, for all generation including de minimis generation, which allows for retrospective payments and payments to all participants.

5. Response to SEM-21-026

5.1 Definition of Dispatch and Redispatch

WEI and RNI members agree with the definition of Dispatch and Redispatch set out in SEM-21-026, namely that 'dispatch relates to the scheduling and dispatch of units to meet the energy requirements of the market', and that 'Redispatch in the SEM relates to deviations from the market schedule for generation for both local network and broader system reasons, including TSO-instructed changes in generation due to localised network issues (constraints) and reduction in non-synchronous generation due to other system-wide reasons such as levels of System Non-Synchronous Penetration (curtailment)'. In the context of renewable units on the system today, in simple terms this means that dispatch relates to actions taken in the ex-ante market to set the unit to its forecast generating position and redispatch relates to actions taken in the balancing market that deviate the unit from its intended generating position, such that renewable units would be dispatched by their sales into the ex-ante markets and redispatched through constraint and curtailment in the balancing markets.

i. Classification of dispatch and redispatch for priority dispatch units

In our view, decremental actions taken on <u>priority dispatch units</u> can be considered either dispatch and redispatch (energy and non-energy actions) rather than as forms of redispatch only (non-energy actions). This is because within the category of priority dispatch, there are two groups of units: non-dispatchable (i.e., wind and solar units) and dispatchable units (i.e., CHP, hydro, waste-to-energy etc.). Any form of action on *non-dispatchable units* with priority dispatch (wind, solar etc.) are forms of redispatch only. As outlined in section 2.1 of SEM-21-026, "*priority dispatch wind and solar units cannot be dispatched for energy balancing purposes"*, and so evidently these actions cannot be dispatch and are always redispatch actions.

However, we believe that *dispatchable units* with priority dispatch can have actions which are forms of dispatch and actions which are forms of redispatch. According to the definitions set out in section 2.1 of SEM-21-026, and the definition of redispatch set out in Article 2(26) of the CEP, an action should only be labelled as redispatch if it is taken to meet an operational constraint or is taken for system-wide curtailment. Certainly, the majority of actions taken on *dispatchable* units with priority dispatch in the balancing market are not taken for these reasons; rather they are taken to meet the energy imbalance and are therefore dispatch actions. We reject the view of the Priority Dispatch hierarchy being a "constraint" - this is evidently not an operational constraint imposed to allow the system to run securely, and so should not fall under the bracket of redispatch as defined in SEM-21-026 or Article 2(26). It should be noted that the Regulatory Authorities defined actions taken on Priority Dispatch units as a form of Dispatch in Fig. 3 of SEM-20-028.

We would have concerns about the two proposed modifications to the balancing pricing mechanism detailed in SEM-21-026 that may come from defining actions on dispatchable units with priority dispatch as redispatch only. The change would either be the implementation of Mod_10_19, which would replace decremental actions applied to dispatchable Priority Dispatch units with a price of 0 €/MWh in imbalance pricing, or the introduction of a new flag to remove priority dispatch units from setting the imbalance price.

It is apparent that both changes would lead to increased balancing market prices, which would subsequently increase prices in the day-ahead and intraday markets as price spreads narrow between the markets. Increased prices have direct impacts on the price consumers must pay for their energy, but also on the flow of power on the interconnectors. If the SEM market price increases, it is more likely that the SEM would import electricity across the interconnectors from GB, in contrast to the SEM's current position as a net exporter. The interaction between interconnector flows and the SNSP limit would have implications for the maximum wind and solar generation the system could securely accommodate in a given period and would lead to increased curtailment across the island. We are very much opposed to any changes to market pricing which would lead to increased dispatch down of renewable generation. Analysis conducted by one of our members shows that dispatch down could increase by 16% annually if either of these proposed changes were implemented.

We believe that the current flagging and tagging process is sufficient to identify actions taken for redispatch and exclude them from the balancing pricing mechanism and that neither of these changes are required.

5.2 Definition of Non-Market Based Redispatch

WEI and RNI members agree with the view of the RAs in SEM-21-26 that curtailment in the SEM is currently a form of non-market based redispatch, as it is applied to all non-synchronous units and is not based on any merit order or the bids and offers of units.

WEI and RNI members strongly disagree with this assertion that constraints as applied to all non-priority dispatch units are a form of market based redispatch. It is our strong position that constraint of renewable generation which occurs on the power system is a form of non-market based redispatch, regardless of priority dispatch status, and therefore should be fully compensated up to the value of the unit's financial support. To ensure fair and even burden sharing, constraints should continue to be applied on a pro-rata basis. We have provided our rationale for taking this position, and arguments supporting this definition, in sections 4.1 and 4.2 of our response.

Building on the arguments put forward in section 4, it must be highlighted that the current proposal from the RAs is already having significant ramifications for new renewable generation seeking to connect to the grid in ROI under RESS-1. These generators bid into the RESS-1 auction on the assumption that constraints would be pro-rated across both priority dispatch and non-priority dispatch generators. The ECP constraint reports carried out by the SOs had these assumptions included when they were provided to generators in advance of the RESS-1 auction bidding.

The current proposals under SEM-21-026 imply that all future wind and solar generation connecting onto the system (which will be non-priority dispatch), will be subject to market-based re-dispatch first to address a network constraint on the power system. It will only be once all market-based re-dispatch options are exhausted those generators with priority dispatch will be constrained down on a pro-rata basis. This means that the levels of constraint which they will experience will be substantially higher than the constraint levels which will be seen by the existing priority dispatch generators on the grid. This will have a very detrimental impact to future renewables energy prices as the generators will need to price in the increased constraint levels to their bids.

If the new ruleset for constraints is implemented as set out in the Consultation, then this means the constraints analyses used by generators in setting their bid prices for RESS-1 last year are completely out of date and no longer relevant. The bid prices submitted would in no way reflect the constraint levels which will be imposed upon them. We are aware that of instances were developers who were successful in RESS-1, have had to halt all progress in progressing projects towards financial close as the Consultation has created enormous uncertainty on the financeability of these projects.

Several of our members have commissioned consultants to carry out new constraint analysis since the Consultation Papers were published and, in some cases, initial results are highlighting a four-fold increase in constraints. Under the current proposals from the SEMC, a number of projects would experience an increase in constraints from an initially forecasted range of 5-8% to 25-40%.

If the proposal proceeds in its current format, it will mean that every successful RESS-1 generator will need to assess again whether proceeding with the project is economically viable. Investors and banks will also re-consider their investment in these projects making it difficult to achieve financial close for those projects that do decide to progress. Furthermore, it will also mean a substantial increase in costs for those projects which are expected to proceed as CPPAs, raising a question over their viability. The implications also apply to future RESS and CPPA projects, and as such we believe such a move would have far reaching consequences for renewable development in Ireland, and the delivery of government targets.

The same issue is also halting the development of several renewable generation projects which were progressing in Northern Ireland (NI). As you will be aware, there is currently no support scheme in place for new renewable generation in NI. As a result, it has been incredibly challenging to develop projects that are financially viable, with no new large scale renewable connections in 2019 or 2020. Although, RNI are expecting new connections from the end of 2021.

However, if the proposal proceeds in its current format, it will mean that projects due to connect in 2021 and beyond will need to assess again whether proceeding with the project is viable. Existing CPPAs will be put at risk and investors and banks will also reconsider their investment in these projects making it difficult to achieve financial close for those projects that do decide to progress. Furthermore, should the GB Contract for Difference (CfD) scheme be extended to NI, as proposed by the Department for the Economy in their Energy Strategy consultation paper, this would result in significantly higher bid prices from NI projects and in effect make them uncompetitive with projects in GB. Energy Strategy ambitions, in respect of the power sector, would become unrealistic as these proposals will result in a further set back to a market that is only beginning to recover from the abrupt ending of the Northern Ireland Renewables Obligation (NIRO).

ii. Renumeration for Constraints

We note from the Consultation that the RAs do not propose any change to the current market mechanisms which are in place for remuneration for constraints. As outlined in section 4.2 of our response, Article 13 of the Clean Energy Package requires that where non-marker based redispatch occurs a generator should be fully compensated including lost benefit. Article 13 is the law as outlined by the European Council and Parliament, as of 1st January 2020, aimed to reduce emissions and deliver renewable generation at the cheapest cost to the end consumer. Whilst the mechanism for compensating priority dispatch generation – through CCURL and CDISCOUNT payments – can stay the same as prior to 1st January 2020, we believe that the value of this compensation cannot.

5.3 RA Proposals for Financial Compensation Under Article 13(7)

WEI and RNI members note the proposal from the RAs to provide financial compensation for non-market based redispatch associated with curtailment. We are aware that the proposal is based on providing different levels of compensation for priority dispatch and non-priority dispatch units based on the value of priority dispatch and to provide a potential incentive for units to voluntarily give up priority dispatch, which may in turn reduce levels of curtailment where units are not run to their availability. We strongly disagree with this approach. Article 13(7) makes no distinction between PD and NPD units on the level of compensation and therefore there can be no distinction. Our members do not believe it is justified or lawful to pay two different rates of compensation.

It is our view that compensation for constraint is also required, in order to comply with the Clean Energy Package. To reemphasise, WEI and RNI members strongly argue that the legal requirements of the CEP need to be implemented in full, specifically the right of all qualifying generation to compensation at the level of financial support for downwards redispatch, including both curtailment and constraint. Please refer to section 4 of our response for further details.

Also, in relation to the Consultation, we note that the RAs are considering whether a limit on compensation under Article 13(7) could be included in future to account for the higher targets of SNSP and levels of non-synchronous generation which can be physically accommodated on the system. In our response to SEM-20-028, our members noted that Options 2-5 in that paper fell short of the full implementation of Article 13 of the Clean Energy Package by placing a cap on the level of compensation paid to the generator. Noting the detailed explanation in Section 4.2 as to unjustifiably high and low compensation we would strongly reject any form of cap being placed on the level of compensation, as is suggested in the Consultation.

5.4 Application of Proposals from 1 January 2020

The RAs note in the Consultation that they are cognisant that the requirement for financial compensation for non-market based redispatching under Article 13(7) came into force on 1 January 2020. It must be stated that compensation for constraint and curtailment exist in the market today through the CCURL and CDISCOUNT payments. Whilst the calculation of the payment amount will need to change, as covered in the point above, the mechanism used could remain the same, though noting our point on R factor reconciliation in section 4.5 of our response.

6. Response to SEM-21-027

6.1 Categories of Units and Treatment in Scheduling and Dispatch

WEI and RNI members are mindful of the RAs proposal in SEM-21-027 to require non-dispatchable units without priority dispatch (such as wind and solar generation) to submit PNs, Commercial Offer Data and Technical Offer Data and be treated as dispatchable units in the SEM. We agree with this approach; however, we wish to highlight that there should be no change as regards the timing for submission of PNs. We would emphasise the need for non-priority dispatch renewables to be able to switch off, as is the case for dispatchable units, when they are not dispatched through the ex-ante markets. We wish to also reiterate our view that constraint for such units should remain on a pro-rata basis regards of dispatch priority for renewable units, and that compensation must apply for any form of redispatch, as required under the Regulation.

From a systems perspective, WEI and RNI have been informed by the SOs that amending the market systems to do so will require non-trivial systems changes. However, WEI and RNI 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. We also wish to draw your attention to our detailed comments on this in section 3.1 of our response.

6.2 Treatment in the Balancing Market

We note from SEM-21-027 the RAs proposal that new units without priority dispatch which are dispatched away from their ex-ante market positions for energy balancing reasons should be considered in dispatch on an economic basis like any other instance of balancing energy, accounting for system security considerations. We would agree that where dispatch is on a market basis, i.e., excluding redispatch actions, namely constraint and curtailment, that dispatching away from PNs should be done on an economic basis in a non-discriminatory and transparent fashion from the same merit order as the rest of the balancing market.

6.3 Bids, Offers and Bidding Principles

SEM-21-026 and SEM-21-027 both reference the intention and likelihood that dispatchable wind, i.e., wind that is now designated as non-priority dispatch, should participate in the market and therefore be subject to bidding principles. We note from SEM-21-027 the RAs view that different rules for Bid-Offer Acceptance, or any changes to their timing or classification, need to be developed to accommodate new renewable units in the market. The Consultation states that ‘where new renewable units have the same COD, pro-rata dispatch down across units with the same COD should be considered in the TSOs’ submission for implementation of the interim and enduring system changes required, noting consistency of treatment with other units in the market.’ From our perspective, we would agree with the Regulatory Authorities that no changes are required.

We note that specifically the Balancing Market Principles Code of Practice (BMPCoP) is referenced with the assumption that this will require separate consideration and consultation. It is unfortunate that more detail was not provided on this critical aspect of the delivery of Article 12 and 13 of the Clean Energy Package. WEI and RNI members see this as a clear void in the Consultation at this stage.

The approach taken to bidding principles, and critically the intended transition from BCOP to BMPCoP is an important area for our members. On the one hand, the Consultation details the market and system changes, the compensation arrangements and treatment. However, on the other hand, the Consultation does not cover the other critical aspects of a market participant's business; namely how they will be allowed to and be able to bid in their costs and participate in the market. Without this critical detail, it is very unclear and uncertain as to the overall landscape of the market following these changes.

It would be our preference that existing BCOP is amended to allow non-priority dispatch plant to bid into the market, rather than BMPCoP. The BMPCoP is currently not in place in the market, was developed in a scenario that did not anticipate dispatchable wind and in our view in its current form, it is not suitable for wind generation. BMPCoP defines an exclusive list of eligible costs, and it also removes some cost items.

At this time with a high degree of uncertainty underpinning implementation of Article 12 and 13, additional uncertainty regarding the application of bidding principles that are currently not in force, specifically for wind generation, would be excessive. In contrast, BCOP is currently operational and known in the market. It would also provide sufficient flexibility for a suitable transition for wind being redesignated as non-priority dispatch. In the absence of any detail as to how the market will transition to the BMPCoP, it is our view that initially, dispatchable wind should be treated like other generators through the BCOP.

We understand that bidding principles is a realm covered by different teams in the RAs to those handling the overall implementation of Article 12 and 13. However, we do not think it acceptable that a coordinated approach and detail could not have been provided to give a full picture of the market landscape following implementation of Article 12 and 13. We would ask that this is progressed as swiftly as possible, and that responses from participants that relate to the bidding principles, are shared with the relevant subject matter experts within the RAs.

6.4 Treatment of Constraints and Curtailment

WEI and RNI members agree with the RAs that curtailment should continue to be applied on a pro-rata basis, however, noting section 4.1 of our response, we believe that constraint in the SEM should also be on a pro-rata basis. Whilst non-priority dispatch units should submit Commercial Offer Data into the markets and be paid different values for their dispatch down, the volumes that they are constrained down by should apply equally to all renewable units as is the current practice today. As previously outlined in this response, we strongly disagree with the RA proposal that constraints will be applied to all non-priority dispatch units on a market-based merit.

6.5 Arrangements for Implementation

In relation to arrangements for implementation of a solution, we welcome the virtual workshop arranged by SEMO and the SOs on 1st July 2021, and furthermore the intention that further RA-SEMO-SO industry workshops will be held on the Regulation to bring in the greatest amount of collective expertise and deliver a solution as soon as a functional and suitable response can be delivered. We outline further thoughts in section 3.1 of this response.

As was already highlighted in section 2 of this response document, we are concerned that any implementation of the Regulation would appear to be some time 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. 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. Any further uncertainty on a live Regulation in a live market creates material commercial uncertainty and risk for all parties involved and presents significant challenges to governments in both Ireland and Northern Ireland in achieving decarbonisation targets.

7. Summary of Response

Wind Energy Ireland (WEI) and Renewable NI (RNI) would like to thank the SEM Committee (SEMC) for the opportunity to respond to the Consultation Papers on SEM-21-026 Dispatch, Redispatch and Compensation Pursuant to Regulation (EU) 2019/943 and SEM-21-027 Proposed Decision on Treatment of New Renewable Units in the SEM.

Like the SEMC and Regulatory Authorities (RAs), WEI and RNI members are committed to playing our part in delivering future targets on emissions reduction and renewable energy at the lowest cost to the end consumer. However, we are concerned that the proposals in these Consultation Papers, if implemented, will significantly adversely impact on the ability of the industry to deliver the required investment to enable Irish and Northern Ireland governments to achieve their decarbonisation targets.

Regulation (EU) 2019/943 creates the binding legislative framework for facilitating the necessary levels of investment at least cost to consumers. The proposals set out in this Consultation, which would only serve to increase cost for consumers and threaten national climate ambitions are, in our view, a direct consequence of a proposed departure by the RAs from the express legal requirements of Regulation (EU) 2019/943. To this end WEI and RNI members urge the SEMC to reconsider the proposed interpretation of Regulation (EU) 2019/943 as currently set out in the Consultation Papers.

Building on this point, WEI and RNI members believe that the proposals set out by the SEMC allocate risk to generators that is impossible for our members to manage, meaning that the cost to consumers of developing further renewable capacity will be significantly greater than is necessary. We are also concerned about impacts on the expected performance of existing investments, with inadequate compensation for higher-than-expected constraint and curtailment in SEM, which is contrary to the requirements of the Regulation.

This response document has been structured to provide feedback on the areas of both Consultation Papers SEM-21-026 and SEM-21-027, which are of the highest priority for our members. The overarching principles of our response, to be viewed as an integrated whole, are to ensure:

- That compensation for dispatch down is compensated as required by law under the Clean Energy Package (CEP). We strongly argue that the legal requirements of the CEP need to be implemented in full, specifically the right of all qualifying generation to compensation at the level of financial support for downwards redispatch.
- That when the provisions of Article 13(3) are considered, constraints (in addition to curtailment) should be considered as non-market based redispatch. To ensure fair and even burden sharing, constraints should continue to be applied on a pro-rata basis.

- That existing BCOP is amended to allow non-priority dispatch plant to bid into the market. The BMPCoP was developed in a scenario that did not anticipate dispatchable wind, and in our view, it is not suitable for wind generation in its current form.
- That risks and incentives, primarily around network constraints, curtailment, and firm access to the grid, need to be allocated to the parties best able to manage those risks.

We believe that a decision underpinning these core principles would facilitate investment in new renewables at an efficient cost for the end consumer, maintain the viability of RESS-1 and CPPA projects in ROI and the equivalent pipeline of projects in NI, and provide for a sustainable investment environment for existing renewable generators in the SEM.

To deliver on these objectives, we have set out several preferred positions (some outside the scope of the SEMC proposed decision and consultation) in our response. These positions seek to achieve a balance between the fair interests of new investment, in-development projects (under RESS-1, CPPAs and merchant projects in NI for example), and existing renewable generators under the terms of the Regulation. They have key interactions, which centre on the allocation of risk for downward redispatch between new renewable generators and priority dispatch generators, and encompass the following elements:

- The allowed bids and offers for redispatch under licence-obligated bidding principles.
- The determination of what generators are entitled for compensation due to the characteristics of their connection offer (i.e., “firmness”).
- The required trading necessary for priority and non-priority dispatch plant to achieve an energy position.
- The extent to which the above three factors will apply to either market-based (Article 13(2)) or non-market-based (Article 13(7)) compensation mechanisms.

Descoping potential change from, and/or misalignment of, one or more of the above elements can lead to an unworkable, non-sustainable, or non-investible market design, undermining the rights of some or all renewable generators under the Regulation, and negatively impacting non-renewable generators, System Operators, and consumers alike. Ambiguity on such elements renders the SEMC proposals non-assessable, and therefore not supportable without clarification on matters upon which the SEMC have not directly consulted, and therefore we can have no confidence will be delivered through further SEMC processes.

We urge the SEMC to ensure that their next step in this process considers all relevant factors (including where necessary, matters under the separate vires of the RAs) on a holistic level. We also request that the Regulatory Authorities refrain from making any decisions on matters in Regulation (EU) 2019/943 in respect of which the Regulatory Authorities have a discretion, until the threshold legal requirements of Regulation (EU) 2019/943, in respect of which the Regulatory Authorities do not have any discretion, are agreed.

In summary, the overarching principles of the WEI and RNI response are to ensure:

1. **That compensation for dispatch down is compensated as required by law under the Clean Energy Package (CEP). We strongly argue that the legal requirements of the CEP need to be implemented in full, specifically the right of all qualifying generation to compensation at the level of financial support for downwards redispatch.**
2. **That when the provisions of Article 13(3) are considered, constraints (in addition to curtailment) should be considered as non-market based redispatch. To ensure fair and even burden sharing, constraints should continue to be applied on a pro-rata basis.**
3. **That the existing BCOP is amended to allow non-priority dispatch plant to bid into the market. The BMPCoP was developed in a scenario that did not anticipate dispatchable wind, and in our view, it is not suitable for wind generation in its current form.**
4. **That risks and incentives, primarily around network constraints, curtailment, and firm access to the grid, need to be allocated to the parties best able to manage those risks.**

Appendix A Engagement with RAs during Consultation

Prior to submitting this Consultation response, WEI and RNI members have spent several months engaged in deep analysis of the proposals and considerations. WEI and RNI have written separately to the CRU and UR respectively, in relation to some initial and substantial concerns. Copies of both letters have been included as attachments to this correspondence.

B.1 Correspondence with CRU, 26th May 2021

B.2 Correspondence with UR, 3rd June 2021

B.3 Correspondence from SEMC, 25th June 2021