COILLTE GROUP

Renewable Energy

Response to

SEM-21-027

Proposed Decision on Treatment of New Renewable Units in SEM

and

SEM-21-026

Consultation on Dispatch, Redispatch and Compensation pursuant to Regulation (EU) 2019/943

9th July 2021

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1.0 Introduction

Coillte Renewable Energy 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.

Prior to setting out our response to this consultation we wish to note to the SEM Committee that the Coillte Renewable Energy business unit (**Coillte RE**) is in the late stages of transitioning to a new stand-alone joint venture company, in conjunction with the ESB. Once established, this new joint venture entity will be one of the largest dedicated developers of onshore wind in Ireland. The transaction completion is subject to final shareholder approval. The team responsible for this consultation response will, post transaction completion, transition to this new business.

Coillte is also a member of Wind Energy Ireland (WEI) and our team actively participate in the various committees and working groups established within the organization, including the working group that prepared the WEI submission on this consultation. Coillte is generally supportive of the positions set out by WEI in their response.

2.0 Context

Before addressing the specific questions raised in the consultation, and noting that some of the points of context below are outside the scope of the current consultation, we believe it would be beneficial to make some high level observations in relation to the likely evolution of the power system in Ireland in the coming decade and beyond, and what that might mean in terms of requirements for efficient markets providing consumer value:

On a 70%+ RES-E system, a low cost system requires low cost renewables

It has been decided at a political level that the majority of the energy demand in the electricity sector will be met by variable renewable energy. When the broader policy context is considered it is extremely likely that ambitions in this regard are only going to increase over time. The vast majority of this energy will be provided by onshore and offshore wind with a potentially material volume of solar energy. This will involve the addition of at least 18TWh of renewable energy p.a. on the system by 2030. +/- €20 per MWh difference in the cost of this energy will result in + / - €360m p.a. in consumer costs. It is therefore clear that if the transition to a 70%+ RES-E system is to be delivered in a manner that is affordable / least cost for consumers then consideration needs to be given to the following question. **What are the most appropriate market structures that would enable the deployment of zero marginal cost variable renewable electricity on the grid at least cost to consumers?** Any answer to this question needs to address the fundamental economics of these technologies. That is, high capex / low to zero marginal cost technologies can be delivered at lower costs when provided with greater revenue certainty. There are a number of key risks that need to be addressed:

Constraint, Curtailment and Energy Balancing / Oversupply

When determining auction bid prices, renewable generators need to include assumptions in relation to the dispatch down from their expected available energy. This involves inserting assumptions into the financial model for constraint curtailment and energy balancing / oversupply in each year for the entire life of the project. i.e. projecting up to 30years into the future. A simple and well understood principle of commercial contracts is that efficient contracts allocate risk to the party best placed to manage it. Taking each of these dispatch down categories in turn:

Local network constraints: The level of future network constraints experienced by an individual generator is determined by the level of investment in the network by the system operators, as supported by the Regulatory Authorities, and by the level and location of future build out of new renewables which in turn is influenced by Government policy, RESS auction volumes, RESS T's and C's and potentially grid connection policy. These are all factors that individual generators have no influence over and therefore have no ability to manage. Market solutions need to be found to appropriately allocate this risk.

System Curtailment: The level of future curtailment is influenced by the level of operational constraints on the system. As has been widely recognised, Eirgrid are world leaders in this space, but national policy is now requiring even more. Achieving a 95% SNSP level and close to zero minimum conventional generation is critical to achieving and exceeding our 70% target while keeping curtailment to manageable levels. This will require the very best of Eirgrid's technical expertise but also regulatory support for the appropriate evolution of the market design to ensure investment in needed new technology. These are all factors outside the control of individual generators bidding into auctions. Options to address this could include firming up the level of curtailment that generators should assume in submitting their bids or alternatively a direct compensation model at the level of support. In understanding the value of such an approach it is critical to recognise that the choice is not to compensate for curtailment or not, it is whether we want to have an efficient direct compensation model or an inefficient indirect compensation model where generators are compensated through their higher auction bids.

Energy Balancing / Oversupply Curtailment: This is a relatively new phenomena in the Irish electricity market and arises when the volume of available renewables (including any conventional generation willing to bid in negative prices) exceeds the level of demand, including interconnector exports. On first inspection it may appear illogical to compensate renewable generators for power that they are unable to provide when the system simply does not require it. However, before reaching that conclusion it is again important to consider the factors that can influence the level of energy balancing / oversupply and which entities are best placed to influence and manage these factors. These factors include

- the delivery of new interconnector capacity,
- The evolution of trading arrangements with GB and France that will impact on interconnector efficiency. These are critical to ensure that interconnector flows are efficient on a first principles basis,
- The rate of demand growth vs the rate of procurement of future renewable capacity,

- Future decarbonisation targets set at a political level, and
- Potentially, by the evolution of capacity markets and congestion management service products that might have ancillary benefits in terms of reducing the level of oversupply.

Again, after an individual generator has been constructed, there is nothing that it can do to influence the level of over supply curtailment that it experiences and it cannot respond to negative prices due to its zero marginal cost. Similar to system curtailment, if this risk is not either firmed up or compensated through appropriate market design evolution then bidders have to factor this into the bids, so once again the choice is effectively between an efficient direct compensation model or an inefficient indirect model. WEI has submitted a proposal to DECC that would have the potential to address these points attached as Appendix 2, a position supported by Coillte's RE division.

Merchant Tail Price Risk (fully outside the scope of the consultations)

Forward wholesale electricity market price modelling of future high RES-E systems shows that as we trend towards a fully decarbonised system, zero marginal cost renewables will earn significantly less in wholesale electricity markets (as designed today). Financial models developed today to support auction bids need to accommodate these low "merchant tail" price forecasts in their bids and this will drive up prices in auctions. There does not appear to be a valid economic theory for exposing high capex, zero marginal cost plant to hourly price signals 15 years after a project has built. There is a simple solution to this problem that would enable lower cost energy provision through RESS auctions and that is longer RESS tenors. Extending the contract periods in RESS from 15 to 25+ years would remove / greatly reduce the risk of very low merchant tail pricing, lowering auction bid prices.

Based on the most recent European renewable support auctions, we would suggest that longer subsidy tenors are becoming more prevalent, and we would highlight the risk that RESS Design Policy is in danger of becoming substantially less attractive in comparison to other markets. Many global RESS auctions now offer subsidy support for 20 years and more recently the proposal for the Polish offshore projects is that that the subsidy tenor will be for 25 years or 100,000 full load hours (and both with indexation of the strike price).

The published proposed decision and consultation on implementation of Art12 & 13 of EU/2019/943 run directly contrary to these principles and are likely to result in significant increased risk and volatility in financial model assumptions and if implemented as currently proposed, could have hugely significant cost implications for consumers.

3.0 Critical Considerations

Of the combined proposals across the Proposed Decision and the Consultation Paper, given the context of the low levels of compensation for downward redispatch and the uncertainty that Ireland and Northern Ireland's non-firm connection access policy creates, the proposal in Section 2.4 that constraints are market-based are the most problematic.

Explanation of Issue

A decision to classify constraints as market based re-dispatch will result in constraints being effectively grandfathered between existing priority dispatch generation and future non-priority dispatch. This will have a number of potentially significant implications.

i) Contracted RESS 1 generators will experience constraints that are potentially several multiples higher than they had originally forecast in their bid prices. This is likely to result in considerable financing difficulties and an inability to progress with construction for some, and very significant financial losses for others.

ii) Future RESS generators would need to price this much higher and much more volatile / uncertain constraint level into their bids along with associated risk premia resulting in substantially higher prices in future auctions and associated higher consumer costs.

Solution

It is Coillte's position that constraints are in fact a form of non-market based re-dispatch and we will set out the detailed justification for this in the main body of the response. This correct interpretation combined with full implementation of compensation provisions of Art13 and an appropriate future firm access policy, has the potential to at least reduce the level of uncertainty that generators need to consider in auction bids and this should provide improved outcomes for consumers.

We will now examine the proposed decision and consultation paper proposals in turn.

4.0 SEM 21-027: Summary of Proposed Decision

The Proposed Decision position is summarised as follows:

- **Section 2.1**: New non-Priority Dispatch renewables which are controllable should interface with standard market systems and submit data equivalent to conventional dispatchable generators.
- **Section 2.2**: New non-Priority Dispatch renewables shall compete on a market merit order for energy balancing. The relationship between ex-ante trades and notifications to the TSO (biased quantities) are to be examined as part of the implementation process.
- **Section 2.3** Non-Priority Dispatch renewables with the same Commercial Offer should be dispatched down (for energy or constraints) on a pro-rata basis. No change to the application of content of the Bidding Code of Practice is proposed, but changes may be considered in the future to accommodate new renewable units taking part in the market without Priority Dispatch.

- **Section 2.4:** Constraints will be applied to all units without Priority Dispatch on a market merit order. This means that all non-Priority Dispatch generators will be dispatched down first (in competition with all other generators) for constraints ahead of Priority Dispatch generators.
- **Section 2.5**: Curtailment, in contrast, will continue to be considered as non-market redispatch given that these rules were established under SEM-13-010. This means that new renewables without Priority Dispatch will be dispatched down on a pro-rata basis with renewables with Priority Dispatch.
- **Section 3**: Implementation proposals shall be received from the TSO within three months of a decision, with interim and enduring solution timeframes (enduring solution to be delivered no later than three years after the decision paper).

5.0 Justification for "non-market based re-dispatch" classification of Constraints

Coillte agrees with the SEM Committee's interpretation of Article 13(1) and Article 13(2) of the Regulation that the intent of the Regulation is to promote and utilise market-based redispatch where possible. Coillte also agrees with the SEM Committee that constraint and curtailment are forms of downward redispatch. In particular, we wish to draw attention to the definition of redispatch in the Regulation, which makes it clear that redispatch incorporates dispatch to manage *"physical congestion or otherwise ensure system security*", i.e. the definition includes both local network constraints / congestion and also system level curtailment.

Article 13 of Regulation EU/2019/943 ("the Regulation") deals with redispatch of energy market participants to resolve system security issues to meet system security concerns. The Article specifies that the TSO 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 TSO may utilise "non-market" based resources to resolve system security issues. This allows the TSO 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).

" 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 Committee have determined that constraint and curtailment are forms of redispatch under the Regulation. The current proposed decision, however, is 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 SEM Committee concluded 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 SEM Committee 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).

This conclusion based on Article 13(1) and Article 13(2) is problematic under three criteria.

5.1 The SEM committee have previously decided that the conditions of Article 13(3)(c) applies in the SEM

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 in **bold**):

"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 SEM Committee have therefore previously determined that there was insufficient competition for constraints in the SEM.

5.2 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.

"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****."* (emphasis added).

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 classify 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.

5.3 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:

"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.

Coillte would also like to point out that constraints are currently subject to comprehensive non-market rules. These rules currently:

- Treat non-Grid Code compliant generators differently to Grid Code compliant generators[1];
- Bundle Grid Code compliant generators into "constraint groups"[2];
- Constrain generators in advance of any required curtailment[3].

This argument is tightly linked to the rationale for current the Bidding Code of Practice (BCOP), which are not under review within this Proposed Decision (although it was noted that the BCOP will be kept under review). For the avoidance of doubt, the rationale provided above that constraints are non-market based does not preclude altering the BCOP to allow recovery of the level of financial support,

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[1] http://www.eirgridgroup.com/site-files/library/EirGrid/Wind%20Farm%20Controllability%20Categorisation%20Policy.pdf
[2] https://www.sem-o.com/documents/general-publications/Wind_Dispatch_Tool_Constraint_Groups.pdf
[3] https://www.sem-o.com/documents/general-publications/Balancing%20Market%20Principles%20Statement%20V5.0

or creating a new compensation outside of the operation of the T&SC altogether. This is discussed later in our response to SEM-21-026 below.

6.0 Curtailment is non-Market Based Redispatch

Coillte agrees with the SEM Committee proposed decision that curtailment is a form of non-market based re-dispatch. The arguments for curtailment being non-market based, in Coillte's view, vary dependent on whether generators have Priority Dispatch or not.

Firstly, there is a large tranche of Priority Dispatch non-synchronous generation which are dispatched down to resolve curtailment. Priority Dispatch under a central dispatch model are generators which are dispatched for energy different to the economic merit order and "*different…from network constraints*". "Network constraints" within the meaning of the Regulation relates to both constraints and curtailment[4], as included in the concept of redispatch.

Correspondingly, Coillte interprets the regulation such that Priority Dispatch plant should not compete on a market merit order to resolve constraints or curtailment. Therefore, Priority Dispatch plant remain non-market based for all downwards redispatch, on the basis of their Priority Dispatch status, and not related to the implementation of Article 13(3).

If generators without Priority Dispatch, given the legacy levels of curtailment existing due to Priority Dispatch generation, were considered to be subject to market-based redispatch for curtailment, the level of downwards redispatch arising would be predictable and material, with a limited number of generators within the market-based redispatch to resolve the issue. Again, competition concerns arise and as such, the curtailment for non-Priority Dispatch generators should be considered as non-market based redispatch.

7.0 Requirements for Future Market-Based Redispatch

Over time, it may be possible to transition this treatment of constraint and curtailment as non-market based redispatch to a market-based solution for non-Priority Dispatch generators, but there are clear tests which must be passed, and requirements which must be fulfilled, and these will likely remain highly problematic on an enduring basis. **As such, it is Coillte's view that non-market based re-dispatch for constraint and curtailment will very likely need to be implemented on an enduring basis.**

Test No. 1: There must be adequate competition

The application of Article 13(3) for constraints and curtailment must no longer apply, i.e. there needs to be sufficient competition for the provision of downward redispatch.

[4] Note that "curtailment" under the Regulation relates to the reduction of – or curtailment of – transmission network capacity.

Test No. 2: All generators must be Compensated on a free market basis without imposition of regulated bidding. Competition for Constraints and Curtailment must not be subject to BCOP or its successor.

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

*"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**."*

As noted in Section 5.2 above, this requirement is not currently met.

In Coillte's opinion, the requirement for adequate compensation leads to follow-on requirements:

Test No. 3: Under Existing Policy, all Generators irrespective of the level of forecast future constraints must be granted Financially Firm Access in order to be Considered Market Based

Finally, Coillte understands that in order for the TSO to schedule many generators competing on a commercial merit-order basis under a central dispatch regime, this will stress the capability of the existing dispatch and scheduling tools. Arguments have been made that central dispatch scheduling and dispatch optimisation tools cannot solve for generation schedules where more than one hundred generators are commercially competing. This leads to one final requirement.

Test No. 4: The central dispatch and scheduling tools must be able to support the ongoing decarbonisation of the electrical system involving the addition of very large numbers of individual generation units, including if necessary moving in time to a self dispatched system.

In the recent TSO workshop (held on the morning of 1st July 2021), these types of performance issues were often referred to by the TSO, and one potential conclusion from this high-level discussion is that moving to market-based redispatch for constraint and curtailment is only prudent within the context of a full European integrated market design, post 2026.

8.0 Further Detailed Comments

8.1 Utilisation of EDIL for Variable Renewable Generators

Coillte believes that the use of EDIL-type declarations and dispatch is completely inappropriate for variable renewable generators for the following reasons:

- EDIL is manual, and relies on 24-7 staffing of facilities (typically onsite, but it can be facilitated remotely). The manual nature of EDIL is appropriate when seeking to dispatch large thermal generation, where onsite safety conditions take primacy over TSO dispatch needs. Such safety concerns are technology dependent, and are not of relevance for variable renewable generation such as wind and solar. **The control regime must be automated**.

- EDIL requires up to 1-second resolution in dispatch instructions. This is inappropriate for a generation source whose availability varies outside of their control on an equivalent basis. This concern also applies to the submission of availability forecasts and final physical notifications. **Dispatch instructions and declarations should be made in a manner consistent with the technical capabilities of the generators**, i.e. the declaration and dispatch instruction sets should include, alongside a MW-set point for constraint and curtailment, a "to the available power" instruction. We draw attention to the requirement of Article 6(1) of the Regulation, which states: "*1. Balancing markets, including prequalification processes, shall be organised in such a way as to: (a) ensure effective non-discrimination between market participants taking account of the different technical needs of the electricity system and <u>the different technical capabilities of generation sources</u>, energy storage and demand.".* It is not appropriate to shoe-horn controllable variable generation into dispatch tools expressly designed for conventional generation, even on a transitional basis.
- The current dispatch and scheduling regime for conventional generation is designed around submission of data from non-priority dispatch generators which is of use for the System Operator in the scheduling and dispatch of the system. There is little additional value for (potentially hundreds) of wind and solar generators submitting availability signals in line with resource forecasts, and obfuscate the underlying forecast technical outage information of the generator. Indeed, this question has already been asked and answered around the lack of obligation of wind generators to submit FPNs to the TSO under the current rules for Priority Dispatch generation within the I-SEM design. **Forecast availability declarations should relate to the outage information, and not resource forecasts.** For the avoidance of doubt, these data submissions relate solely to *available* power declarations. Non-Priority Dispatch controllable generators will need to be able to notify to the TSO that they do not want to generate at certain periods, e.g. if the Day-Ahead price is less than zero for RESS generators.
- The current dispatch regime deals only with participant generators. This should not be a requirement for de minimis generation. **A dispatch regime for de minimis generation should be facilitated,** i.e. it is not appropriate to require generators to become a market participant in order to achieve a physical dispatch.

8.2 Trading and Eligibility for Compensation

The consultation dealt with certain matters in relation to how:

i. Generators which had not traded their full output ex ante may be allowed to run to their full availability (in the discussion around biased quantities); and
ii. Penalties such as Uninstructed Imbalances that may arise should be examined.

Coillte has a number of detailed comments in relation to these issues.

- Final Physical Notifications (FPN) in principle should be aligned with achieved ex ante trades (QEX). Where there is a divergence due to QEX being below the FPN, this creates a Biased Quantity, which disapplies the right to compensation for downwards redispatch. **The entire regime regarding the ex ante markets being the exclusive route to physical dispatch needs review for renewables**. Consideration should be given to:

  - The incentives for all classes of generators for their FPN to deviate from their QEX;
  - The resulting distortion of identification of energy balancing vs curtailment which may arise as a result in real-time dispatch. Please see an Appendix 1 for an example of this.

- **Portfolio trades for renewable generators should be facilitated**. Currently, the existing regime is highly restrictive. Each generator currently requires an ex-ante market registration, and individual forecast, and that trade to be linked to a Balancing Market participant registration in order to submit an FPN and receive compensation for downwards redispatch (constraints). With compensation for constraint and curtailment (subject to consultation SEM-21-026) more emphasis will be taken on achieving these individual ex ante positions. This raises a number of issues:
  - The number of ex ante market registrations will increase. Not all generators have utilised explicit ex ante trading to manage their balance responsibility (de minimis generation, non-firm generation). It is difficult to point to another European market where a 10MW generator needs to register in the pan-European EUPHEMIA day-ahead algorithm to achieve a physical dispatch. There are operational sustainability issues for SEMOpx.
  - The cost of ex ante market registrations to individual smaller generators is prohibitive. Excluding clearing house fees, the costs of market participation for a 10MW solar farm is €0.50/MWh for the annual SEMOpx trading unit registration;

- **Trading risk should not result in delivery risk for Non Priority Dispatch renewable and HE CHP generators (or renewable and HE CHP generators should not be subject to a "trading curtailment risk").**

  This is related to Point 1 and Point 2 above, and Coillte understand that the SEM Committee may be aligned at least in part with this position. Renewable generators – and the polices they fulfil – wish to maximise their available output. This is efficient for consumers who are paying through subsidy for the decarbonisation agenda. Where traders have made a legitimate attempt to trade and schedule the generator for delivery, the dispatch regime should not restrict the output of that generator arising from forecast errors (either in securing a trade, or submission of subsequent FPN).
  - The SEM Committee have already proposed that generators should not be exposed to Uninstructed Imbalance charges under such circumstances.
  - Related to the form of the dispatch instruction (and the non-suitability of only MW-level dispatch from EDIL), if a trader has attempted to trade the full output of the windfarm (but has under-forecast production) but the TSO is satisfied that no constraint or curtailment needs to apply, the generator should be allowed – in full compliance with Grid Code – to generate at full output even if the "dispatch" received at a MW level by the generator is in line with the trader's submitted FPN.

  In particular, we believe that there is limited difference in a market rule which forces a renewable generator to run below its preferred output (accepting balancing responsibility), or such actions being taken after the fact by the TSO. Article 13(5) does state that the TSO shall take: "take appropriate grid-related and market-related operational measures in order to minimise the downward redispatching of electricity produced from renewable energy sources or from high-efficiency cogeneration". Coillte believes that appropriate forbearance for renewable and HE CHP generators in relation to the link between ex ante trades and FPNs relative to conventional generators would reflect this intent of the Regulation.

9.0 SEM-21-026 Summary of Consultation Proposals

The Consultation makes several proposals which overlap with the Proposed Decision, and these will not be reiterated here. The SEM Committee propose further positions (and seek comment on them) in the Consultation Paper:

- **Dispatch and Energy Balancing:** A question is raised whether Priority Dispatch generators can be utilised for Energy Balancing, i.e. Balancing Market actions taken by the TSO;
- **Price Setting:** There are a number of questions as to whether Priority Dispatch generators can therefore set the price in the Imbalance Market if they are called for Energy Balancing;
- **Market Based Redispatch:** Market based redispatch shall be compensated under the existing T&SC rules. This only applies to constraints for non-priority dispatch renewables. (All other downward redispatch is considered non-market based);
- **Non-Market Based Redispatch (Curtailment)**: It is proposed to treat Priority Dispatch generation differently to non-Priority Dispatch generation. Priority Dispatch renewables such as wind and solar are to be compensated at the level of the opportunity cost (zero) whereas non-Priority Dispatch renewables are to be compensated at the level of the ex-ante trade achieved, as long as they have a financially firm connection offer.
    - This difference in treatment is justified by the value that Priority Dispatch entails, and therefore <u>any</u> compensation for curtailment (beyond direct costs incurred) is considered overcompensation.
    - Non-Priority Dispatch generators are not compensated at the level of financial support based on:
        - The fact that there never has been compensation before;
        - A review of compensation in other jurisdictions for wires-based congestion, while noting the “unique” nature of the SEM vis-à-vis curtailment; and
        - Dispatch and redispatch decisions should “arguably” be based on marginal cost of generation and system security positions and should not relate to the compensation levels from support schemes foregone.
- **Retrospective Payments:** The SEM Committee propose various mechanisms to retrospectively implement the Regulation to the date of its legal effect.

10.0 Analysis of the SEM Committee Proposals

In terms of the assessment of the level of financial compensation for non-market based dispatch, Coillte is aligned with the Wind Energy Ireland position.

- The SEMC is interpreting the Regulation in line with their local statutory objectives. It is unclear that such considerations are in fact a lawful approach to the implementation of the Regulation. It is Coillte’s understanding that Regulations, in contrast to Directives, must be implemented as written without reliance on stretching interpretation where the text has a plain English meaning and intent.

- It is Coillte's view that the SEMC have misinterpreted the "unjustifiably high" provision of the Regulation. It is not reasonable for the SEMC to have a view of the long-run profitability of the generator when determining the level of financial compensation.
- The SEMC have implied that the Regulation is not written with curtailment (as defined in SEM) in mind, but rather with congestion in mind and correspondingly, believe that the application of Article 13(7) is de facto inappropriate for curtailment, and as such feel justified in that compensation for curtailment is at the level of financial support is unjustifiably high. It is not clear the SEM Committee have such discretion to interpret the Regulation in such a manner. Indeed, as referenced earlier in our response, redispatch clearly encompasses SEM "curtailment", and specifically it is not within the SEM Committee's gift to refuse compensation for one from of redispatch over the other, irrespective of the local market conditions. (the definition of redispatch in the Regulation *"physical congestion* ***or otherwise ensure system security***".
- The allowed T&SC-mechanisms for compensation for redispatch[5] are highly regulated today, and does not allow compensation at the level of financial support. The T&SC mechanism-based compensation for constraints (whether market based or non-market based under the Regulation) is therefore not sufficient;
- Continued compensation for Priority Dispatch plant under the existing T&SC basis for non-market constraint is justified on the basis that non-market based compensation should not be less than market-based compensation. Rather than engaging with this logic, Coillte notes that the appropriate test is that compensation must be applied pursuant to Article 13(7).

11.0 Firm Access Policy

The current connection agreement regimes offer financially firm access to electricity markets once all the Associated Transmission Reinforcements associated with the connection agreement are complete. Nearly all projects currently in development have non-firm access. Particularly in the case where there is a) grandfathering of constraint for priority dispatch renewables and b) there is no timely "firm access" for new RESS generators, this leaves generators very exposed to material levels of unpredictable constraints. For future renewable auctions, this very high uncertainty will likely result in unnecessarily high auction prices. While outside the scope of the current consultation it is critically important that new firm access policy is introduced as soon as possible and in advance of the next RESS auction, to provide generators with certainty on firm access dates.

[5] These are compensation only for firm generators, subject to achieving an ex ante trade, with SRMC-mandated complex offers. For the avoidance of doubt, just because the Balancing Market rules, the T&SC, are proposed to be the mechanism by which generators are compensated for redispatch, does not make such compensation "market based" as defined under the Regulation.

12.0 Payments Methodology (and Retrospective Payments)

While there are benefits with leveraging existing market systems to provide for compensation for **non-market** based redispatch (namely avoiding the cost of implementing a new system), there are advantages to considering a separate settlement system.

- It allows the existing bidding principles and financially firm access policy to remain in place, and not disrupt the wider market (and the forward looking assumptions made by all market players on which long-term contracts are based);
- It requires no changes to the market systems (which have material lead times for implementation);
- It allows both de minimis generators and generators make claims for any redispatch compensation. Coillte suggests that the correct payment account should be nominated by the generation licence holder, and it would be generation licence holder's responsibility to update as necessary, reducing overhead for the TSOs;
- It ensures that Dispatch Balancing Costs managed by the TSO remain assessed on the basis of the cost of production of generation (and not the financial support receivable by any class of generation) assuming that compensation ultimately will be paid at the level of financial support;
- The system can be used to implement retrospective payments (avoiding stranding of a system to do so – as the T&SC does not facilitate retrospective settlement); and
- It also allows appropriate assessment of "unjustifiably high" or "unjustifiably low" compensation for specific cases, without the need to implement further changes in the market systems and the need to answer the challenge of non-equity of treatment from all other market participants.

Appendix 1:

Dispatch Categorisation Issues Arising from FPNs

FPN's deviating from ex-ante trades can blur the lines between dispatch for energy balancing, and redispatch for curtailment.

Scenario: 5000MW demand, 2150MW non-synchronous available renewables with priority dispatch, 2150MW non-synchronous available renewables without priority dispatch. All renewables achieve 4300MW QEX in the ex-nte markets. Conventional generators achieve 700MW QEX in the ex-ante markets. Maximum allowed SNSP is 80%, meaning only 4000MW of renewable generation can be scheduled in dispatch.

If:

- The Conventional Generation FPNs at 1000MW (through a mix of 700MW FPN being technically infeasible and/or commercially disadvantageous). System Operator has 5300MW of FPNs. Considers that 300MW of non-priority dispatch renewables should be dispatched down as energy balancing.
- The Conventional Generation FPNs at 700MW. System Operator has 5000MW of FPNs and 5000MW of demand, but needs to curtail 300MW and dispatch up 300MW of conventional generation. 300MW of curtailment is shared pro-rata across non-priority dispatch renewables and priority dispatch renewables.

In conclusion, conventional generation nomination approaches can impact the identification of actions as energy balancing or curtailment close to real-time with potential to impact disproportionately on dispatch of new non-PD renewables.

Appendix 2:

WEI position paper submitted to DECC

Attached separately