Single Electricity Market

(SEM)

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

SEM-20-028

27 April 2020

EXECUTIVE SUMMARY

This Consultation Paper focuses on the implementation of Article 12 'Dispatching of generation and demand response' and Article 13 'Redispatching' under the new Electricity Regulation which forms part of the Clean Energy Package. This will involve an update to SEM-11-062 to reflect the new requirements introduced by the Regulation in relation to priority dispatch. It will also involve an update to SEM-13-010 regarding compensation for curtailment to reflect the new requirements introduced by the Regulation.

Section 1 of this paper outlines the main requirements under Article 12 and 13 and considers the definitions of dispatch, redispatch and market based/non-market based redispatching in the SEM context. This considers the central dispatch model in the SEM, whereby the generation schedules, consumption schedules as well as dispatching of power generating facilities and demand facilities are determined by the TSOs (EirGrid and SONI) as part of an integrated scheduling process. The distinction between dispatching and redispatching actions taken by the TSOs in this context is difficult in comparison to self-dispatching systems given that these occur almost simultaneously in the balancing market timeframe in the SEM.

'Dispatch' in the SEM relates to the scheduling and dispatch of units to meet the energy requirements of the market, as part of the scheduling and dispatch process managed by the TSOs and outlined in the Balancing Market Principles Statement. The TSOs must take account of operational security, efficient operation of the SEM and the maximisation of priority dispatch as part of this process.

Article 12 of the Regulation effectively removes priority dispatch for new renewable generators using renewable energy sources or high-efficiency cogeneration commissioned after 4 July 2019 (without prejudice to contracts concluded before 4 July 2019) bar certain exemptions, in order to facilitate a non-discriminatory, transparent and market-based system. Section 2 of this Paper outlines the current framework for priority dispatch in the SEM, while Section 3 outlines a number of proposals for implementation of Article 12 in relation to changes to priority dispatch and the treatment of dispatchable and non-dispatchable units.

This includes proposals for the treatment of 'new' renewable units (both dispatchable and non-dispatchable) which no longer have priority dispatch under Article 12 in the scheduling and dispatch process and the information they might be required to submit in terms of Physical Notifications, Commercial Offer Data and Technical Offer Data. Section 3 also considers the treatment of 'new' renewable units which no longer have priority dispatch where they are subject to dispatch down for energy balancing purposes (i.e. where there is excessive generation) under Article 12. The RAs have also considered revisions that may be required to update the current priority dispatch hierarchy, given the period of time that has passed since it was initially implemented and requirements under the new Electricity Regulation.

Rules around how priority dispatch will be applied to units with a capacity of less than 400 kW and to demonstration projects following RA approval and the rules for priority dispatch ceasing to apply to units which are subject to significant modifications under Article 12 (e.g. to new connections or increases in generation capacity, etc) are also considered in Section 3.

Section 4 of this Consultation Paper considers the implementation of Article 13 of the new Electricity Regulation, which relates to requirements for redispatching of generation and demand response. Under Regulation 2019/943, 'redispatching' means:

'a measure, including curtailment, that is activated by one or more transmission system operators or distribution system operators by altering the generation, load pattern, or both, in order to change physical flows in the electricity system and relieve a physical congestion or otherwise ensure system security.'

The RAs have interpreted redispatching in the SEM to relate to the reduction of generation for both local network and broader system reasons, including TSO-instructed reduction 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).

The RAs are of the view that in the case of the application constraints, as these take account of Commercial and Technical Offer Data submitted by Participants to minimise the cost of diverging from PNs, in the SEM this is a form of market-based redispatch and is remunerated through Balancing Market Settlement. In the case of curtailment, this is currently applied on a pro-rata basis to all non-synchronous units (as per the Decision in SEM-13-010) due to system-wide reasons and is not selected based on submitted bids of particular units. In the RAs' view this represents a form of non-market based redispatching.

While this Consultation Paper considers the implementation requirements for both Article 12 and 13 of the new Electricity Regulation, it is the RAs' view that Article 13 in relation to redispatch applies to all units with no discrimination between renewable generators commissioned before or after 4 July 2019. On this basis, there is no distinction between old and new renewable generation under Article 13 for the purposes of the application of curtailment in the SEM and this does not introduce any prioritisation in relation to curtailment of priority and non-priority dispatch renewable generation.

SEM-13-010 removed payment of compensation for curtailment. However, Article 13(7) requires that financial compensation should be provided by the System Operator to units with a firm connection which are subject to non-market based redispatching. Article 13(7) states;

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.'

The RAs' considerations in terms of the appropriate level of compensation to be provided by the System Operators in the case of non-market based redispatching are outlined in Section 4 of this Consultation Paper. The RAs are of the view that the balance of risk between consumers and generators, the utility of curtailed electricity and the limited funding available to invest in programmes to reduce the overall level of curtailment and facilitate higher levels of renewables on the system are important considerations in terms of the implementation of Article 13(7) of the new Electricity Regulation. The high level of instantaneous renewable generation in the SEM in comparison to the majority of EU Member States is also an important consideration, along with the focus in the Regulation on congestion management rather than specifically on curtailment as it is defined in the SEM.

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1. Introduction

1.1 Clean Energy Package Background

The Clean Energy for all Europeans package consists of eight legislative acts which were adopted by the European Parliament and European Council in 2018 and 2019 following Commission proposals in November 2016. This involves a comprehensive update of the EU's energy policy framework aimed at enabling the transition to cleaner energy and facilitating a reduction in greenhouse gas emission levels of 40% by 2030 compared to 1990.

The eight legislative acts within the CEP cover a range of actors and stakeholders in the energy sector including Member States, regulatory agencies, network operators and market participants. The Regulation seeks to amend aspects of wholesale electricity markets in Europe, enhance integration and progress the transition to renewable energy. Having entered into force in July 2019, the majority of the articles in the Regulation apply from January 2020.

A high-level review was conducted by the RAs in the second half of 2019 to identify the areas of the revised Regulation on the internal market for electricity (EU) 2019/943[1] which may require action by the SEM Committee with respect to the all-island SEM. The review found that the revised SEM, which went live on 1 October 2018, is already compliant with many articles of the Regulation. However, the RAs identified six key outstanding areas which will likely require action by the SEM Committee in 2020, along with coordination with relevant Government Departments in Ireland and Northern Ireland, in order to progress implementation of the Regulation. Based on this review, a Roadmap for progressing these six areas in 2020 was outlined by the SEM Committee in an Information Paper published in December 2019[2].

Two of the areas identified in the Information Paper relate to Article 12 'Dispatching of generation and demand response' and Article 13 'Redispatching'. Options for the implementation of these Articles in the SEM are the focus of this Consultation Paper. This will involve an update to the provisions outlined in SEM-11-062[3] to reflect the new requirements introduced by the Regulation in relation to Priority Dispatch. It will also involve an update to the provisions outlined in SEM-13-010 regarding compensation for curtailment to reflect the new requirements introduced by the Regulation.

[1] Regulation (EU) 2019/943 on the internal market for electricity.
[2] SEM-19-073 Roadmap to Clean Energy Package Implementation
[3] SEM-11-062 Principles of Dispatch and the Design of the Market Schedule in the Trading and Settlement Code SEM Committee Decision Paper

This paper outlines the RAs' proposals in order to ensure compliance with the requirements of these aspects of the Regulation by mid-2020, noting that a longer lead-in time will be required in order to implement these changes in practice in scheduling and dispatch and market systems. Interim measures that may be required to ensure compliance with this Article in 2020 are also discussed in this paper.

Responses to this Consultation Paper are invited until 22 June 2020 and can be provided to gkelly@cru.ie and Gary.Mccullough@uregni.gov.uk. During this 8-week consultation phase the RAs also intend to hold a series of meetings with interested stakeholders to discuss each of the elements raised in this Consultation Paper, invite early feedback from stakeholders and provide answers to any questions interested stakeholders may have in responding to the Consultation. The RAs acknowledge that a number of complex issues are considered in this Consultation Paper and further workshops may be required as part of this process. The RAs also acknowledge that due to the range of issues considered in this paper, a further consultation or proposed decision process may be required before final decisions are made by the SEM Committee in relation to the implementation of Articles 12 and 13.

1.2 Overview of Requirements under Articles 12 and 13

Article 12 'Dispatching of generation and demand response' and Article 13 'Redispatching' of the new Electricity Regulation introduce a number of requirements which will require changes to aspects of the design of the Single Electricity Market. An overview of the requirements included in each Article is provided here along with the RAs' interpretation of the definition of dispatch, redispatch and market based/non-market based redispatching in the SEM.

There are currently two types of dispatching arrangements in place across European electricity markets, self-dispatch systems and central dispatch systems. The SEM operates a central dispatch model, whereby the generation schedules, consumption schedules as well as dispatching of power generating facilities and demand facilities are determined by the TSOs (EirGrid and SONI) as part of an integrated scheduling process. Energy balancing and congestion management are performed simultaneously as part of this process along with ensuring that the TSOs meet reserve capacity requirements in real time. The distinction between dispatching and redispatching actions taken by the TSOs in this context is difficult given that these occur almost simultaneously in the balancing market timeframe. In the SEM, the scheduling and dispatch process incorporates a range of activities associated with the close to real-time planning and the real-time operation of the power system.

Self-dispatching models are more common in the EU and involve scheduling agents of power generating facilities and demand facilities determining their own generation and consumption schedules and dispatch. Scheduling agents communicate their anticipated position to the TSO, which takes control of balancing supply and demand closer to real time, with penalties applied for deviations from units' positions. In the case of self-dispatching models, the distinction between initial dispatch by scheduling agents and redispatching actions taken by TSOs is clearer.

1.2.1 Article 12: Dispatching of Generation and Demand Response

'Dispatch' in the SEM relates to the scheduling and dispatch of units to meet the energy requirements of the market, as part of the scheduling and dispatch process managed by the TSOs and outlined in the Balancing Market Principles Statement[4]. The TSOs must take account of operational security, efficient operation of the SEM and the maximisation of priority dispatch as part of this process. Under the Trading and Settlement Code, a Dispatch Instruction means '*an instruction given by a System Operator in relation to a Generator Unit which is Dispatchable or Controllable which relates to the required level of Output of Active Power or mode of operation'*.

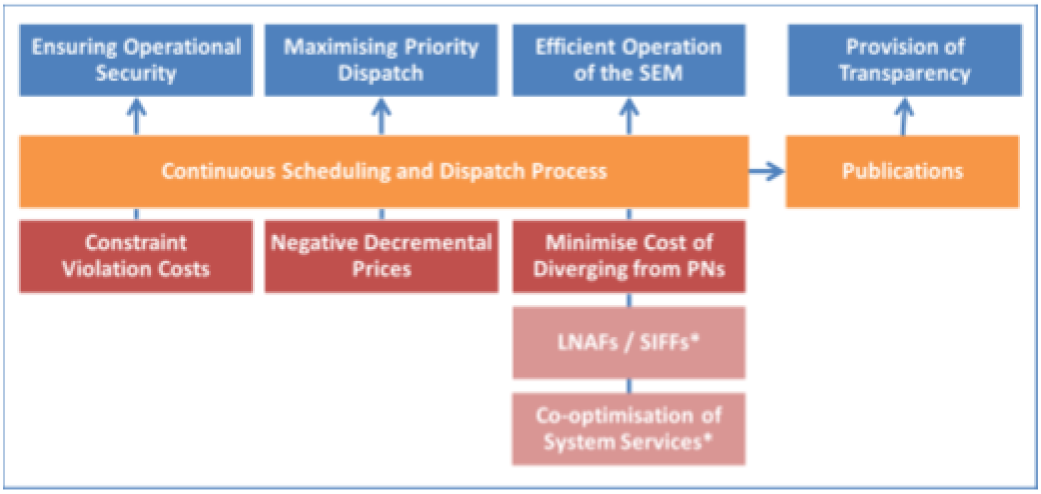

Figure 1, Overview of Scheduling and Dispatch Process and obligations on TSOs

As shown in Figure 1, the facilitation of priority dispatch is a key component of the scheduling and dispatch process. It is related to and influences the TSOs' other obligations as part of this process to ensure operational security and operate the SEM as efficiently as possible and has a knock-on impact on the balancing market. The design of the revised SEM arrangements,

[4] https://www.sem-o.com/documents/general-publications/BMPS_V3.0.pdf

which went live in October 2018, is based on the continuation of priority dispatch for all eligible units and as a result, some fundamental parts of the market design need to be considered in light of the new requirements under Article 12.

Within the scheduling and dispatch process, the concept of balancing energy is also important to consider. In the first instance, the TSOs schedule as far as possible to the Physical Notifications submitted by market participants – physical notifications (PNs) being linked to generator participants' ex ante market positions. In addition to the PNs, the TSOs procure energy to balance supply and demand, based on the mismatch between scheduled and actual positions in real time. The differences between parties' scheduled or market positions and their actual, metered positions are settled at the Imbalance Settlement Price.

Priority dispatch concerns the priority order provided to renewable energy sources in the dispatch hierarchy which is afforded under EU legislation and legislation in Ireland and Northern Ireland. Under the new Electricity Regulation, this is defined as the dispatch of power plants on the basis of criteria which are different from the economic order of bids, and from network constraints, giving priority to the dispatch of particular generation technologies.

The Regulation allows a significantly wide scope for the interpretation of priority dispatch to allow Member States to reflect their specific systems, as this has been implemented in different ways in different jurisdictions. For example, in some cases there are separate provisions for 'priority dispatch' and 'guaranteed' or 'priority access' to the grid. In some Member States, priority dispatch is explicitly mentioned in national legislation while in others it is implicitly provided as part of support schemes which include certain purchase obligations. To understand the intention of the Regulation, and how to consider its implementation in the SEM, it is important to understand the distinction between these concepts in the wider European context and the local one.

In the SEM, priority dispatch is implemented as part of the TSO's scheduling and dispatch process which is outlined in the Balancing Market Principles Statement. Priority dispatch generation is comprised of dispatchable[5] units (e.g. peat, hydro, CHP) and non-dispatchable (but generally controllable[6]) units (wind and solar). A core feature of the scheduling and dispatch process is that the output of these units is maximised as far as technically feasible. The TSOs are required to give priority to generating installations using renewable energy sources in so far as the secure operation of the national electricity system permits, based on transparent and non-discriminatory criteria.

[5] Broadly meaning that the unit can be turned 'on' and 'off', as the fuel source is available at any time.
[6] Broadly meaning that the level of output of the unit can be turned 'up' and 'down'.

Priority dispatch: Under Regulation (EU) 2019/943 this means, with regard to the *self-dispatch model*, the dispatch of power plants on the basis of criteria which are different from the economic order of bids and, with regard to the *central dispatch model*, the dispatch of power plants on the basis of criteria which are different from the economic order of bids and from network constraints, giving priority to the dispatch of particular generation technologies.

Article 12 of the Regulation effectively removes priority dispatch for new renewable generators using renewable energy sources or high-efficiency cogeneration commissioned after 4 July 2019 (without prejudice to contracts concluded before 4 July 2019) bar certain exemptions, in order to facilitate a non-discriminatory, transparent and market-based system.

Existing renewable generation commissioned prior to 4 July 2019 will continue to be eligible for priority dispatch as implemented under the current market arrangements. Article 12(6) states that priority dispatch shall no longer apply to power generating facilities from the date on which such facilities are subject to significant modifications where a new connection agreement is required or where the generation capacity of the power generating facility is increased. In addition, the Regulation provides for Member States to provide incentives to installations eligible for priority dispatch to voluntarily give up priority dispatch.

With respect to the removal of priority dispatch for new renewable generators (those commissioned after 4 July 2019), certain new renewable generation and demand-side facilities are excluded from these requirements, covering:

- New renewable energy generating facilities with an installed electricity capacity of less than 400kW. From 1 January 2026, priority dispatch will apply only to power generating facilities using renewable energy sources with an installed electricity capacity of less than 200 kW.

- Generators, energy storage facilities and other demand-side response units demonstrating innovative technologies, subject to approval by the regulatory authority with a limitation to such priority for the time and extent necessary for achieving the demonstration purposes; and

- Power-generating and facilities using high-efficiency cogeneration with an installed electricity capacity of less than 400 kW.

1.2.2 Article 13: Redispatching

Requirements for redispatching of generation and demand response are considered under Article 13 of the new Electricity Regulation. Under Regulation 2019/943, 'redispatching' means:

> '*a measure, including curtailment, that is activated by one or more transmission system operators or distribution system operators by altering the generation, load pattern, or both, in order to change physical flows in the electricity system and relieve a physical congestion or otherwise ensure system security.*'

In Member States where self-dispatch occurs, redispatching is primarily used for the purpose of congestion management. In the SEM the distinction between dispatching and redispatching is less intuitive as dispatching, energy balancing and redispatching all occur across the same time-horizon. Unlike in other jurisdictions, there is not a clear point where dispatch ends and redispatch begins.

Based on this consideration and the definition above, the RAs have interpreted redispatching in the SEM to relate to the reduction of generation for both local network and broader system reasons, including TSO-instructed reduction 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).

While the definition in the Regulation does not discriminate between curtailment and constraints, there is a clear distinction between these in the SEM. Curtailment is also defined differently across different Member States. In some cases this is a term used for the reduction in renewable generation due to oversupply of available renewable generation or due to local transmission constraints, as opposed to the definition used in the SEM (as any reduction in non-synchronous generation due to system-wide reasons such as levels of System Non-Synchronous Penetration).

The following definitions of constraints and curtailment in the SEM used by EirGrid and SONI are useful for reference. For avoidance of doubt, where constraints or curtailment are referenced in this Consultation Paper they refer to these definitions.

Constraints: This refers to the dispatch down of generation due to localised network reasons, where only a subset of generators can contribute to alleviating the problem. Constraints can occur for two main reasons;

1. More generation than the localised carrying capacity of the network.
2. During outages for maintenance, upgrade works or faults.

Curtailment: This refers to the dispatch down of non-synchronous generation for system wide reasons, where the dispatch down of all such generators would alleviate the problem. There are different types of system security limits that necessitate curtailment;

1. System stability requirements (synchronous inertia, dynamic and transient stability).
2. Operating reserve requirements, including negative reserve.
3. Voltage control requirements.
4. System Non-Synchronous Penetration (SNSP) limit.

While this Consultation Paper considers the implementation requirements for both Article 12 and 13 of the new Electricity Regulation, it is the RAs' view that Article 13 in relation to redispatch applies to all units with no discrimination between renewable generators commissioned before or after 4 July 2019. On this basis, there is no distinction between old and new renewable generation under Article 13 for the purposes of the application of curtailment in the SEM and this does not introduce any prioritisation in relation to curtailment of priority and non-priority dispatch renewable generation. Curtailment will therefore continue to be applied to generators in the SEM regardless of whether they are eligible for priority dispatch under Article 12 or not.

Redispatching: Under Regulation (EU) 2019/943 this means '*a measure, including curtailment, that is activated by one or more transmission system operators or distribution system operators by altering the generation, load pattern, or both, in order to change physical flows in the electricity system and relieve a physical congestion or otherwise ensure system security*'.

Article 13 of the new Electricity Regulation also references 'market based' and 'non-market based' redispatch (but does not include a definition of these). Article 13 (6) sets out a number of principles which apply where non-market based downward redispatching is used which need to be taken account of in terms of a new order for non-market based redispatching, stating that renewable energy sources should only be subject to non-market based downward redispatching if no other alternative exists or if this would result in disproportionate costs or risks to network security. The Article also states that electricity generated in a high-efficiency cogeneration process shall only be subject to downward redispatching if, other than downward redispatching of power-generating facilities using renewable energy sources, no other alternative exists or if other solutions would result in disproportionate costs or severe risks to network security. In effect, this introduces a new redispatch hierarchy associated with the application of non-market based downward redispatching.

In terms of the distinction between 'Market Based' and 'Non-Market based' redispatching in the SEM, the RAs' view is that the primary difference between the two is whether the decision on which units to redispatch follows an economic merit order or not. There are two areas to consider here, constraints and curtailment.

Figure 2 provides a graphical interpretation of the difference between dispatch and redispatch. Where a RES unit is turned down to ensure energy supply is balanced with demand, this is an example of dispatch, while turning a RES unit down below the demand level due to curtailment or constraints is an example of redispatch in the SEM.

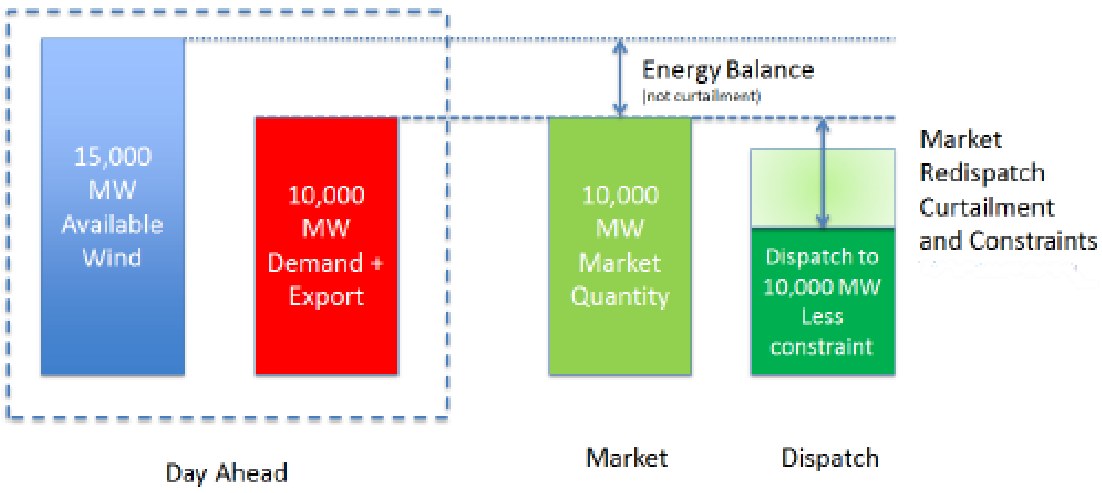

Figure 2

Constraints impose limits on the physical operation of units in order to maintain operational security requirements and due to localised network reasons. A key element of the scheduling and dispatch process is the application of these constraints to units' Physical Notifications (PNs) to produce a physically secure schedule, while minimising the cost of diverging from PNs. This feeds into the Imbalance Pricing process through the setting of System Operator Flags or Non-Marginal Flags.

The RAs are of the view that in the case of the application constraints, as these take account of Commercial and Technical Offer Data submitted by Participants to minimise the cost of diverging from PNs, this is a form of market-based redispatch. There is a price associated with the each of these constraints which the TSOs ‘see’ and respond to as part of the scheduling and dispatch process. The flagging process then identifies the TSO action, referred to as a Bid Offer Acceptance (BOA), driven by system or unit constraints (thus applying either a SO or non-marginal flag), which is then excluded from setting the imbalance price.

In terms of compensation, there are market rules in place for generators whereby if a unit is firm and is constrained below its ex-ante market position, the unit has no balancing market settlement but retains their ex-ante market revenue. If a non-firm unit is constrained below their ex-ante market position, any action to turn a unit down in the range above their Firm Access Quantity is considered an imbalance, rather than a redispatch action, as the market position of the unit is not firm above their Firm Access Quantity level. This imbalance is purchased by the generator unit at the Imbalance Settlement Price. While this second situation exposes the generator to some pricing risk (the risk that the imbalance price will be higher than the DAM price at which they originally sold) this is a risk that can be managed by the generator themselves through forecasting and active trading.

In the case of curtailment, this is currently applied on a pro-rata basis to all non-synchronous units as per the Decision in SEM-13-010 due to system-wide reasons and is not selected based on of the prices submitted by market units. In the RAs’ view this represents a form of non-market based redispatching.

Under the current market rules, if a unit is firm and is curtailed below their ex-ante market position, then the quantity of curtailment is settled at the Curtailment Price. This is also the case for non-firm units. In effect, units do not retain their ex-ante revenue for the amount they have been curtailed below their market position but are not exposed to the imbalance price.

SEM-13-010 removed payment of compensation for curtailment. However, Article 13(7) requires that financial compensation should be provided by the System Operator to units with a firm connection which are subject to non-market based redispatching. Article 13(7) states that ‘*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.'*

The principles for an appropriate level of compensation for non-market based dispatching are considered in Section 4 of this Consultation Paper.

In summary, the RAs have interpreted the terms used in Articles 12 and 13 as per Figure 3 and these are summarised Table 1 below. This interpretation has informed subsequent sections of this Consultation Paper.

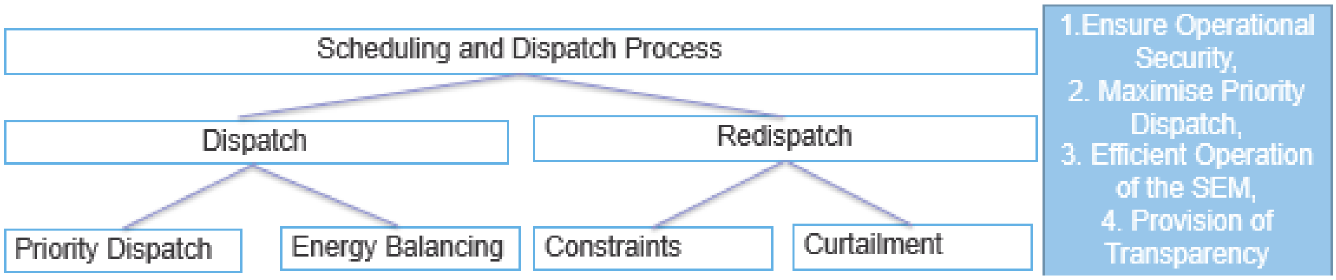

Figure 3

Dispatch	Redispatch	Market Based & Non-Market Based Redispatching
The scheduling and dispatch of units to meet the energy requirements of the market, as part of the scheduling and dispatch process managed by the TSOs and outlined in the Balancing Market Principles Statement. Under the Trading and Settlement Code, a Dispatch Instruction means '*an instruction given by a System Operator in relation to a Generator Unit which is Dispatchable or Controllable which relates to the required level of Output of Active Power or mode of operation*'.	Under Regulation 2019/943, 'redispatching' means '*a measure, including curtailment, that is activated by one or more transmission system operators or distribution system operators by altering the generation, load pattern, or both, in order to change physical flows in the electricity system and relieve a physical congestion or otherwise ensure system security*.' In the SEM this takes place as part of real time dispatch related to the application of constraints and curtailment in the balancing market Timeframe.	The RAs are of the view that in the case of the application constraints, as these take account of Commercial and Technical Offer Data submitted by Participants to minimise the cost of diverging from PNs, in the SEM this is a form of market-based redispatch. Curtailment is currently applied on a pro-rata basis to renewable generators due to system-wide reasons and is not selected based on Bids or Offers of particular units, which in the RAs' view represents non-market based redispatching.

Table 1, Interpretation of terms used in Articles 12 and 13

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

1.3 Purpose of this Paper

Having set out at a high level the RAs' broad interpretation of the intent of Articles 12 and 13 and how they interact with the SEM's central dispatch approach, the RAs have identified a wide range of questions which need to be addressed. The remainder of this Consultation Paper sets out the RAs' thinking on these issues along with consultation questions. The following sections set out in more detail, the core issues set out in Section 1.2, including further background on the legislation or licence requirements in place that impact the current processes. Having set out the background to the issues, the paper then sets out the RAs' views, and poses relevant consultation questions.

This Consultation considers a number of issues including;

1. The interpretation of terms used in Articles 12 and 13 concerning dispatch, redispatch, market based/non-market based redispatch in the SEM, a central dispatch system where dispatch and redispatch occur almost simultaneously in the balancing market timeframe.

2. The treatment of ‘new’ renewable units (both dispatchable and non-dispatchable) which no longer have priority dispatch under Article 12 in the scheduling and dispatch process and the information they might be required to submit in terms of Physical Notifications, Commercial Offer Data and Technical Offer Data.

3. The treatment of ‘new’ renewable units in terms of Balancing Market Settlement under Article 12.

4. The treatment of ‘new’ renewable units which no longer have priority dispatch where they are subject to dispatch down due to energy balancing purposes (i.e. where there is excessive generation) under Article 12.

5. Any revisions required to update the current priority dispatch hierarchy, given the period of time that has passed since it was initially implemented and requirements under the new Electricity Regulation.

6. The rules around how priority dispatch will be applied to units with a capacity of less than 400 kW and to demonstration projects following RA approval, also considering the decrease for eligible installed capacity to 200 kW in 2026 under Article 12.

7. The rules around priority dispatch ceasing to apply to units which are subject to significant modifications under Article 12 (e.g. to new connections or increases in generation capacity, etc).

8. The provision for Member States to provide incentives to installations eligible for priority dispatch to voluntarily give up priority dispatch under Article 12.

9. Any revisions required to introduce a new ‘non-market based redispatch’ hierarchy pursuant to Article 13.

10. Determination of the appropriate level of compensation for non-market based redispatching (for curtailment) in the SEM under Article 13.

The RAs welcome stakeholder's views on a number of specific points in this Consultation Paper and also more general feedback on the RAs interpretation of the Regulation.

2. Current Framework for Priority Dispatch in the SEM

To comply with Article 12 of the new Electricity Regulation, various changes will need to be made to the current priority dispatch framework and new measures will need to be introduced for the treatment of non-priority dispatch units which would previously have been eligible for priority dispatch under preceding legislation, including dispatchable and non-dispatchable units. The RAs are also considering any changes which are merited to the priority dispatch order to reflect recent market developments including the new market arrangements which went live in October 2018.

In the first instance, it is useful to set out how priority dispatch currently operates in the SEM and the legislative basis for this. The current framework for priority dispatch in the Single Electricity Market was set out in SEM-11-062[7] in August 2011. Subsequent SEM Committee papers dealt with tie-break scenarios and rules around the application of curtailment and constraints.

2.1 Relevant Legislation

Article 16 of Directive 2009/28/EC of the European Parliament and of the Council on the promotion of the use of energy from renewable sources (the RES Directive) provides that Member States are required to ensure that when dispatching electricity generating installations, TSOs shall give priority to generating installations using renewable energy sources in so far as the secure operation of the national electricity system permits based on transparent and non-discriminatory criteria.

Article 15 of Directive 2012/27/EU of the European Parliament and of the Council on energy efficiency provides that Member States are required to ensure that, subject to requirements relating to the maintenance of the reliability and safety of the grid, based on transparent and non-discriminatory criteria set by the national regulatory authorities, TSOs are required to provide priority dispatch of electricity from high-efficiency cogeneration in so far as the secure operation of the national electricity system permits.

[7] SEM-11-062 Principles of Dispatch and the Design of the Market Schedule in the Trading and Settlement Code

The obligation to provide priority dispatch to certain classes of generators is also provided for in national legislation, namely: (for Ireland) Section 21 of S.I. No. 217/2002 - Electricity Regulation Act 1999 (Public Service Obligations) Order 2002 (as amended); and (for Northern Ireland) Article 11AB of the Electricity (Northern Ireland) Order 1992, which refers to the criteria set out in the SEM Committee Decision Paper SEM-11-062.

Specific obligations are placed on the TSOs to provide priority dispatch to certain classes of generators in legislation, Licences and the Grid Codes.

EirGrid has a role "*to operate and ensure the maintenance of and, if necessary, develop a safe, secure, reliable, economical and efficient electricity transmission system*" in both law (Clause 8, S.I. 445 2000) and licence (TSO licence Condition 3). It also has to ensure "*when dispatching generating units….*" to *"…. give priority to generating units using energy from renewable sources in so far as the secure operation of the electricity system permits*" (S.I.147,2011).

Under Condition 9A of its licence, SONI is required to comply with the Priority Dispatch Principles, which mean '*the principles, processes, rules and criteria determined and published by the Authority for the purposes of ensuring that certain types of generation sets are afforded priority dispatch in accordance with the requirements of Article 16(2) of Directive 2009/28/EC on the promotion of the use of energy from renewable sources, as amended from time to time by the Authority.'*

Certain provisions of legislation, Licences and Grid Codes may need to be amended to account for the new requirements introduced under the Clean Energy Package.

2.2 Current Priority Dispatch Hierarchy

The TSOs give priority to the dispatch of certain types of units by ensuring that the output of such units is maximised as far as technically feasible. Currently, the approach set out below is employed by the TSOs when dispatching units with priority dispatch. Parties with mandatory priority dispatch under EU Directives (including renewables, qualifying hybrid plants, high efficiency CHP) are given priority over those afforded priority dispatch at the discretion of a Member State (peat). SEM-11-062 also requires the TSOs to review this hierarchy on an annual basis and make submissions to the SEM Committee where necessary. The current hierarchy is as follows;

1. Re-dispatch of conventional generation and SO counter trading on the interconnector after Gate Closure;
2. Peat Stations
3. Hybrid Plant[8]
4. High Efficiency CHP/Biomass/Hydro
5. Solar/Tidal/ Windfarms, and within windfarms
    i. windfarms which should be controllable but do not provide this;
    ii. windfarms which are controllable;
    iii. windfarms which are exempted or are not expected to be controllable
6. Interconnector re-dispatch;
7. Generation the dispatch down of which results in a safety issue to people arising from the operation of hydro generation stations in flooding situations.

Solar and Tidal generation were not included in the 2011 Decision Paper but were subsequently included in the hierarchy by the TSOs pursuant to a letter from the SEM Committee on 24 March 2017 which confirmed that they could be entered onto the priority hierarchy in the same position as wind generation, without prejudice to the outcome of any consultation reviewing the wider priority dispatch hierarchy. This priority dispatch order is summarised in Figure 4.

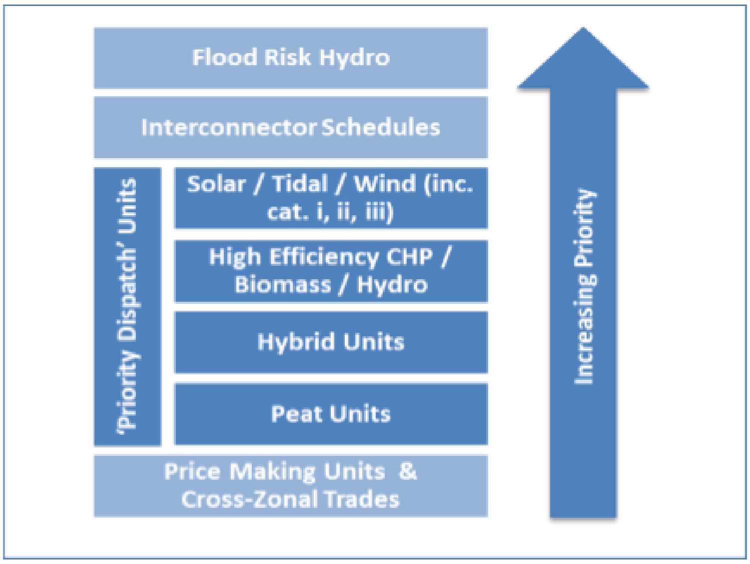

Figure 4, Current Priority Dispatch Order

[8] Assumes certification by relevant competent authority that specific plant qualifies for priority dispatch and renewable status.

A generic term has been introduced to represent the specific technology types of Wind Farms, Solar and Tidal units for the purpose of reporting on controllability, which are represented as 'Power Park Modules' (PPMs). Within this category, there are sub-categories reflecting PPM controllability. Controllability refers to the ability of the TSOs to limit PPMs' output to a specific level, with uncontrollable wind farms for example being dispatched down by opening circuit breakers.

The TSOs publish a monthly controllability status update which sets out the categorisation of each unit as level (i), (ii) or (iii) reflecting the hierarchy above. The TSOs carry out controllability testing in order for controllability status to be given to PPMs. The most recent controllability status update from January 2020[9] provided the breakdown of PPMs outlined in Table 2 below.

PPMs connected as of December 2019	Ireland (MW)	Northern Ireland (MW)
Should be controllable but do not provide this (i)	0	26.9
Controllable (ii)	3,477.02	1,098.44
Exempted or not expected to be controllable (iii)	281.54	0
Total	3,758.56	1,125.34

Table 2

Where a threat to public safety exists due to a flooding situation, consideration is given by the TSOs in dispatch decisions and processes to dispatch hydro-electric stations in the SEM in a manner that minimises this threat to the appropriate degree. The above hierarchy also does not apply where there is a need to address a specific issue in dispatch to maintain the secure operation of the electricity system that requires the dispatching down of a specific generator or generators. This hierarchy also sits within other dispatch requirements related to the treatment of interconnector schedules and cross zonal trade.

[9] http://www.eirgridgroup.com/site-files/library/EirGrid/2020-01-January-Controllability-status-update.pdf

2.3 Implementation of Priority Dispatch in the SEM

The SEM Committee's Building Blocks Consultation Paper consulted on, among other things, how priority dispatch should be implemented under the revised market arrangements, given the importance of the Balancing Market and Imbalance Settlement for priority dispatch.

In the SEM, the TSOs are obliged to take energy from priority dispatch units ahead of other generators, subject to system security considerations. Such units participate in the markets like any other units but receive special treatment in system balancing. Within the scheduling and dispatch process, priority dispatch units are allocated a range of pre-determined negative decremental prices, reflecting their relative position in the priority dispatch hierarchy (the higher the priority the more negative the decremental price). These are applied so that the optimisation engine avoids these actions as they would result in a high cost, however decremental actions can still be applied to avoid violation of any operational security constraints which have a higher violation cost. Predefined priority dispatch prices are substituted for any submitted decremental price for the purpose of scheduling and dispatch however these do not feed into balancing market pricing or settlement. Negative decremental prices applied to priority dispatch units in the scheduling and dispatch process can also be tuned to account for potential conflicts with other constraints or the prices of other units.

In order to accommodate priority dispatch generation in the SEM, balancing actions may be taken by the TSOs on units which do not have priority dispatch where there is excessive generation to meet demand. The TSOs may also apply redispatch through the dispatch up or down of units in order to satisfy operational constraints. If this does not resolve the issue, priority dispatch units will then be moved from their availability according to the priority dispatch order outlined in Figure 4.

If, after applying the hierarchy between plant categories identified as set out above, for the purpose of implementing priority dispatch, the System Operators still have to choose between qualifying priority dispatch units, they are required to follow the principle of firm capacity having priority over non-firm capacity in constraint group areas and, between firm capacities, date order should determine priority (i.e. earlier date preferred over later date) in so far as this is feasible, otherwise a pro-rata approach is followed.

Priority dispatch generation is comprised of dispatchable units such as peat, hydro and CHP and non-dispatchable (but generally controllable) units such as wind and solar. Dispatchable units are required to submit Physical Notifications (PNs) and priority dispatch status applies to their PN quantities, with any availability above this treated in normal economic order.

Non-dispatchable units may also submit PNs however the TSOs use their own forecast of availability to schedule these units to their full actual availability subject only to operational security constraints. A description of dispatchable and non-dispatchable units and the information they are required to submit to the TSOs is provided in Table 3.

Dispatchable Unit	Non-dispatchable but controllable unit	Non-dispatchable and non-controllable unit
A unit is “dispatchable” if it can follow (maintain) MW set-point instructions issued by the TSO. A dispatchable unit with a capacity exceeding the de minimis threshold of 10 MW is required to participate in the balancing and capacity markets.	A unit is “non-dispatchable but controllable” if the unit can limit its output to MW set-point instructions issued by the TSO. A non-dispatchable but controllable unit with a capacity exceeding the de minimis threshold is required to participate in the balancing and capacity markets and is subject to imbalance settlement rules in the T&SC.	A “non-dispatchable and non-controllable” unit is any unit that cannot follow a MW set-point instruction from the TSO. A non-dispatchable and non-controllable unit cannot participate in the balancing market.
e.g. Hydro, CHP	e.g. Wind, solar	e.g. Wind, solar
Required to submit Physical Notification (PN), Technical Offer Data (TOD) and Commercial Offer Data (COD).	May submit Physical Notification (PN) but this is not currently used in the scheduling and dispatch process by the TSOs.	May submit Physical Notification (PN) but this is not currently used in the scheduling and dispatch process by the TSOs.

Table 3

SEM-15-064[10] set out the principles for priority dispatch under the new market arrangements, whereby priority dispatch generation may trade in the day-ahead and intraday markets and decide on the PN its market position, with any incremental offers and decremental bids reflecting the prices at which it is willing to deviate from its PN. Non-dispatchable Participants are not required to submit PNs but may elect to do so for information purposes. The TSOs use their own forecasts for output as an implicit PN for these non-dispatchable units.

[10] SEM-15-064 Energy Trading Arrangements Detailed Design Building Blocks Decision Paper

For non-dispatchable generation the FPN represents the availability of the generation unit. Priority dispatch units are settled at the imbalance price for any volumes not sold ex-ante and cannot set the imbalance price with their priority dispatch volume.

3. Proposals for Implementation of Article 12

Proposals for implementation of each of the areas under the new Electricity Regulation highlighted in Section 1.2 are discussed here and comments are invited from interested stakeholders on the options presented for implementation along with additional issues for consideration.

3.1 Eligibility for Priority Dispatch

Article 12 of the Regulation states that there will be no change in eligibility for priority dispatch for any units commissioned on or before 4 July 2019, without prejudice to contracts concluded before 4 July 2019. In such cases, priority dispatch eligibility will be 'grandfathered' to certain units.

Prior to energisation of new connections, units agree a commissioning programme with the TSO with fixed timelines. Where this commissioning programme has been agreed on or before 4 July 2019, it is proposed that such units will be eligible for priority dispatch. Where a unit is eligible to be processed to receive a valid connection offer by 4 July 2019, the RAs are of the view that this represents a contract concluded before priority dispatch ceases to apply under Article 12 and that such units are also eligible for priority dispatch.

In addition, the RAs welcome feedback in this Consultation on the treatment of active projects with a specific route to market before 4 July 2019 which can be evidenced, such as a REFIT letter of offer of Power Purchase Agreement which has been concluded before this cut-off date. Where such generators become active under contracts concluded before 4 July 2019 including a REFIT letter of offer or PPA, the RAs welcome feedback on the proposal for such generators to be eligible for priority dispatch. For the avoidance of doubt, this would not include projects which subsequently become active under a contract concluded after this date.

3.2 Treatment of 'new' renewable units in scheduling and dispatch

As discussed in Section 3.1, under Article 12, there will be units in the SEM which retain priority dispatch under existing legislation and new units which would have previously qualified for priority dispatch such as renewable energy generators and high efficiency co-generation along with conventional generators. These are summarised in Table 4.

Unit Types	Dispatchable/non-dispatchable
Priority Dispatch units (PD units)	Includes dispatchable and non-dispatchable units
New units which would have previously qualified for priority dispatch (non-PD units)	Includes dispatchable and non-dispatchable units
Conventional Generators	Dispatchable units

Table 4

A distinction will need to be made between any priority dispatch units and 'new' renewable units which are not eligible for priority dispatch within the TSOs' scheduling and dispatch systems. This needs to account for dispatchable and non-dispatchable but controllable units, as well as the small number of non-controllable PPMs outlined in Section 2 of this Consultation.

Any changes to accommodate this also need to consider the market data requirements for each unit type which provide inputs to the scheduling and dispatch process and the existing systems used by the TSOs. The Scheduling and Dispatch process is built around the Balancing Market and is the mechanism by which the TSOs dispatch units to manage constraints, provide system services and dispatch balancing energy. An overview of the inputs and outputs of the Scheduling and Dispatch process is provided in Table 5.

Inputs	Processing	Outputs
Physical Notifications	LTS, RTC, RTD sequences	LTS, RTC, RTD schedules
Commercial Offer Data	Composite Cost Curve Calculation	Dispatch Instructions
Unit Technical Data	Merit Orders	SO and Non-Marginal Flags
Unit Availability	Application of Constraints	Reports
Transmission Availability		
Demand Data		
Policy parameters		
Operational Constraints		
Ancillary Services Requirements		

Table 5

Physical Notifications represent units' intended output excluding and accepted offers and bids. These are used along with units' incremental and decremental cost curves to form a composite cost curve that is used within the scheduling and dispatch process. Technical Offer Data is used to validate Physical Notifications, develop schedules of units based on their technical capability and ensure that dispatch aligns with units' technical characteristics. Commercial Offer Data (COD) is used as an input to scheduling and dispatch as the basis of minimising the cost of diverging from participants' Physical Notifications.

Dispatchable units are required to submit Physical Notifications (PNs), Technical Offer Data (TOD) and Commercial Offer Data (COD) representing among other things their incremental and decremental costs to move from their ex-ante position, by Gate Closure of the Trading Day (13:30 day-ahead). Participants can update their PNs and COD after this time and up to Gate Closure of the Imbalance Settlement Period to reflect their intraday trading activity or any update to their balancing offers and bids. A participant's PN submission represents the participant's best estimate of its intended level of generation and expected trade volumes. At gate closure, these are linked to ex-ante trades, i.e. FPNs which reflect traded volumes. This information is required for dispatchable generators, for which participation in the balancing market is mandatory, regardless of their priority dispatch status. Any incremental volume submitted by dispatchable generators with priority dispatch does not have priority dispatch status and is treated like any other volume in the balancing market, while any decremental price is used for settlement purposes only and cannot set the imbalance price.

PNs are optional for non-dispatchable but controllable/non-controllable generators while COD and TOD is not required as these units are run to their availability. Currently, all such units fall under priority dispatch. Non-dispatchable Participants are not required to submit PNs but may elect to do so for information purposes. The TSOs use their own forecasts for output as an implicit FPN for these non-dispatchable units.

There are three cases to consider in terms of any changes required to facilitate the removal of priority dispatch eligibility;

(1) new dispatchable units which would have previously qualified for priority dispatch;
(2) new non-dispatchable but controllable units which would have previously qualified for priority dispatch; and,
(3) new non-dispatchable non-controllable units which would have previously qualified for priority dispatch.

In the case of (1), the RAs' understanding is that as non-renewable dispatchable units are already required to submit PN, TOD and COD data to the TSOs, this change in priority dispatch eligibility can be facilitated through the current scheduling and dispatch processes in place using the Balancing Market Interface (BMI) and EDIL systems. Currently, any incremental volume submitted by such generators is treated like any other volume in the balancing market. The main difference from a system perspective for such units would be that the entirety of their volume would be taken as part of the economic merit order and such units could set the imbalance price.

In the case of (2), for non-dispatchable but controllable units, the majority of which are currently wind units, the TSOs take account of the TSO's wind forecast and real-time availability information from their Energy Management System as inputs for the Wind Dispatch Tool. Currently, the TSOs procure wind power forecasts from two providers which include the forecast power output from each wind farm greater than or equal to 5MW. These forecasts are merged with current wind conditions on a continuous basis for use in the scheduling and dispatch process. While wind participants may submit PNs representing their forecast production, these are not used in the scheduling and dispatch process at present and current systems automatically set the PN of a wind unit as equal to its availability.

In order to accommodate such units without priority dispatch, they may need to be categorised as dispatchable within the Market and be registered as such. As part of this Consultation, the RAs have requested feedback from the TSOs on what system changes are practically required to facilitate the change to such units being considered in the scheduling and dispatch process in the same manner as other volumes in the balancing market in order to be compliant with the Regulation. The RAs are cognisant of the potential cost and time involved in implementing such changes. The initial response provided to the RAs states that any system changes would impact on scheduling systems, EDIL, WDT, EMS and that a full impact assessment would need to be carried out in order to estimate the cost and timelines associated with implementing any changes pursuant to Article 12.

On this basis, the RAs are considering whether non-priority dispatch non-dispatchable but controllable units will be considered effectively as dispatchable or under a new separate category and what changes are needed to facilitate this. This would mean that such units would run at their FPN, which could in theory be less than their maximum availability, be settled at the imbalance price for any difference from volumes sold ex-ante and could set the imbalance price. Such units would register as dispatchable within the market under which the TSOs would be able to issue MW set-point instructions to the unit via EDIL.

In addition, the treatment of PNs, TOD and COD for such units needs to be considered, both for the purpose of scheduling and dispatch and balancing market settlement (which is discussed further in Section 3.3.) Under the new requirements of the Electricity Regulation, the dispatch of such units without priority dispatch will be market based, increasing the importance of non-dispatchable units' PN and COD data for the purpose of their ex-ante position and balancing market settlement. There is a question of whether such units should be obliged to submit PNs and COD. In order to submit this information, they would need to have systems in place to submit a FPN to the TSOs and accept and follow dispatch instructions. Alternatively, a rule could be introduced whereby if no PN is submitted, the unit is assigned a deemed PN calculated by the TSOs as per the process today (based on the unit's maximum availability considering system security). Where a unit chooses to submit a PN, the TSOs would be required to use this as long as it does not deviate above a certain percentage of the TSOs' own forecast availability of the unit. It is likely that only dispatchable plants with non-zero marginal costs would wish to avail of any provision to submit an FPN lower than its maximum available output. The unit's ex-ante position as represented by its PN would then be the basis of any balancing market settlement.

In the case of (3) for non-dispatchable and non-controllable units, currently these cannot submit bids and offers to the TSO in the balancing market, as such units cannot follow a MW set-point instruction from the TSO. This Consultation proposes that such units would continue to have the option to provide a PN to the TSOs for information purposes, with any imbalances settled at the imbalance price.

As an alternative to the detailed changes described above for cases (2) and (3) and as a possible interim measure, taking account of the zero marginal cost nature of non-dispatchable but controllable generation in the market today (i.e. wind, solar), units no longer eligible for priority dispatch could be scheduled to their availability as per the process today on the assumption that this reflects economic dispatch in any case, but where there is excessive generation on the system such units would be subject to energy balancing prior to any priority dispatch units (energy balancing is discussed further in Section 3.3).

Consultation Question 2: In terms of the practical implementation of Article 12(1) to introduce a distinction between units which retain eligibility for priority dispatch and those which are not eligible, the RAs propose;

- Where a commissioning programme has been agreed with the TSOs on or before 4 July 2019, it is proposed that such units will be eligible for priority dispatch.
- Where a unit is eligible to be processed to receive a valid connection offer by 4 July 2019, the RAs are of the view that this represents a contract concluded before priority dispatch ceases to apply under Article 12 and that such units are also eligible for priority dispatch.

- Where a unit becomes active under a contract concluded before 4 July 2019 including a REFIT letter of offer or PPA, the RAs welcome feedback on the proposal for such generators to be eligible for priority dispatch.

Interested stakeholder's views are invited on these proposals.

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

Consultation Question 4: It is proposed that any unit which is non-dispatchable but controllable and is no longer eligible for priority dispatch would run at their FPN, be settled at the imbalance price for any volumes sold ex-ante and could set the imbalance price.

As part of this proposal, there is a question of whether such units would be required to submit FPNs or where no FPN is submitted, the unit could be assigned a deemed FPN calculated by the TSOs as per the process today. Where a unit elects to submit an FPN, in this case, the TSOs would be required to use this as long as it does not deviate above a certain percentage of the TSOs' own forecast availability of the unit.

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

In particular, the RAs are seeking feedback from the TSOs on measures which can be introduced to facilitate required compliance with the new Electricity Regulation within the scheduling and dispatch and balancing market systems.

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

3.3 Treatment of 'new' renewable units in energy balancing

Section 3.2 of this Consultation Paper considers the provisions for the treatment of new non-priority dispatch 'dispatchable' and 'non-dispatchable' generators within the scheduling and dispatch process, while this Section considers the treatment of such units in terms of energy balancing.

The RAs have interpreted the requirements introduced by the new Regulation, along with the current market design, to mean that any units no longer eligible for priority dispatch may be subject to energy balancing actions by the TSOs like any other unit in the market, ahead of any actions taken on priority dispatch units. The Balancing Market reflects actions taken by the TSOs to keep the system in balance, reflecting differences between the ex-ante market schedule and actual supply and demand.

Under the Electricity Balancing Guideline, 'balancing energy' means the energy used by the TSOs to perform balancing and provided by a balancing service provider. In the SEM energy balancing services are offered into the Balancing Market by generators and Demand Side Units.

New generators which are no longer eligible for priority dispatch will be subject to energy balancing actions by the TSOs, considered in dispatch economically and settled like any other instance of balancing energy. This section considers options for the treatment of energy balancing actions taken by the TSO in relation to 'non-dispatchable' generators in particular.

Where the available scheduled generators exceed the total demand based on the FPNs provided to the TSOs, i.e. the market is long and the Net Imbalance Volume (NIV) is negative, the TSOs are required to balance scheduled generation (and demand response) to the required level of demand, with these actions treated on a commercial merit order basis with all non-priority dispatch classes of generation. Where there is excessive generation to meet demand, priority dispatch units will be scheduled first, subject to system security considerations. In the case of excessive generation, dispatch down of other units will be required based on economic merit order (accounting for operational and system security considerations). One option for non-dispatchable but controllable units would be for decremental bids to be used to rank these units against other non-priority dispatch generators, however there are two issues to consider in relation to this.

The first issue relates to the considerations outlined in Section 3.2 in terms of the time and cost involved to implement system changes for different classes of units which are no longer eligible for priority dispatch to be treated in the same manner as other volumes in the balancing market. The RAs have requested further information on the practical implementation issues associated with this change from the TSOs, which in their initial response have stated that currently the TSOs' system does not accept COD from generators where the fuel type is 'wind' and while changing the configuration of the systems would address this, such units would still have to be treated differently as this would only account for dispatch down and not dispatch up.

If such changes could be implemented, the decremental bids submitted by such units would be used by the TSOs in dispatch down for energy balancing purposes. However, it might be expected that zero-marginal cost generation would have similar short run marginal costs which could lead to convergent bid prices. Complex offers under the BMPCOP[11] are comprised of start-up costs for committing a unit, no-load costs for each trading period and incremental offer/decremental bid curves associated with increasing or decreasing energy. A separate ruleset might be required for the application of bids for zero-marginal cost generation and feedback is requested as part of this Consultation on the most appropriate method to implement this. In addition, even in a situation where decremental bids can be used to rank these units, a tie-break rule would be required to distinguish between units where prices are the time. The RAs propose that this could entail balancing actions being applied on a pro-rata basis where bids (or offers) are the same.

Where an alternative mechanism is required to implement this change in the interim for system reasons, this could allow for a separate ruleset to be applied to units which are not currently catered for within the EDIL system, for example a pro-rata treatment of all such units for any balancing actions (i.e. dispatch down due to excessive generation) taken by the TSOs. These units would be dispatched down in this case ahead of priority dispatch generation for the purpose of balancing energy.

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

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

[11] See SEM-17-048 Balancing Market Principles Code of Practice Decision Paper

Consultation Question 8: What is your view on a potential rule-set being implemented for non-dispatchable units where (a), systems cannot facilitate ranking of decremental bids for such units for balancing actions for a certain time period and/or (b) where convergent bid prices require a tie-break rule?

3.4 Proposed Revisions to the Priority Dispatch Hierarchy

As part of the SEM Committee's Decision under SEM-11-062, the TSOs were requested to advise a proposed approach to dispatch generators qualifying for priority dispatch where there are choices to be made between such plants. The SEM Committee requested that the following factors be considered by the TSOs when making their submission for the initial priority dispatch hierarchy:

- The requirement to maintain the reliability and safety of the system;
- Security of supply;
- Costs to customers, including constraint costs and costs arising from the application of losses; and
- The requirement for transparency and objectivity.

Following adoption of the TSOs' proposed priority dispatch hierarchy, in SEM-11-062 the SEM Committee requested the TSOs to review this hierarchy annually and resubmit proposed changes to the SEM Committee for consideration. Priority dispatch has been used in the SEM to date as a mechanism to achieve broad energy policy outcomes, in line with the requirements of previous Renewable Energy Directives.

As part of this Consultation Paper, an updated submission was requested from the TSOs which is provided below. The RAs do not propose any change in this Consultation Paper from the 'absolute' interpretation of priority dispatch as set out in SEM-11-062, i.e. that priority dispatch generation shall have full priority for delivery of physical power, subject only to security and safety concerns and interconnector flows.

The TSOs' proposal for a revised priority dispatch hierarchy is as follows;

1. Market position allocated based on cleared ex-ante and balancing market trades for all participants that solves energy balancing and SNSP restrictions;

2. Where there is a need in operation to dispatch down from these market quantities then dispatch down High Efficiency Cogeneration / Biomass/ Waste to Energy to minimum generation (level where they are considered autoproducing: if they are not an autoproducer turn off);
3. Wind, Solar, Tidal, Hydro;
    a. Windfarms which should be controllable but are not in practice
    b. Windfarms which are controllable;
    c. Windfarms which are exempted or are not expected to be controllable;
4. Dispatch down High Efficiency Cogeneration / Biomass/Waste to Energy off,
5. Interconnector schedules; and
6. Generation the dispatch down of which results in a safety issue to people.

The RAs note a number of elements in relation to this proposal. The first point in the suggested hierarchy is intended to give a market position for units and states that it should solve the energy balancing and SNSP restrictions for all participants. The RAs have a question on the explicit consideration of one system limitation (SNSP level) versus all constraints and requirements that the TSOs need to consider in dispatch to maintain the secure operation of the electricity system and request further information on this proposal and how it would interact with the current scheduling and dispatch process, ex-ante markets and balancing markets.

Secondly, the proposed hierarchy no longer considers peat plants, which may need to be considered further in the context of existing Member State level legislation in this area (Peat is provided with discretionary priority dispatch unit under the indigenous fuel S.I.217, 2002).

The second point of the proposed hierarchy looks at dispatch down of existing priority dispatch High Efficiency Cogeneration/Biomass/Waste to Energy units to their minimum generation in terms of a level where they are considered to be autoproducing, in order to account for the demand requirements of such units for their on-site processes to continue unaffected by dispatch down requirements. The RAs would request that the TSOs in their response to this Consultation Paper confirm that an autoproducer in this context means a Demand Site where the Demand is not solely for the purpose of Generation.

The TSOs noted in their submission for a revised hierarchy that as part of the operation of a power system with high RES, it is more secure to turn down units which have a certain energy output over multiple hours, than those that are more uncertain. In such a case, the TSOs suggest that in a revised hierarchy hydro and tidal might be dispatched down ahead of wind and solar units. In addition, within the wind category there are subcategories reflecting the controllability of wind farms, however the controllability categorisation process for Solar and Tidal units needs to be defined.

Each category of technology included in the hierarchy is briefly described in Table 6 below.

Category	Description
Conventional Participants	Where market position is allocated based on ex-ante and balancing market trades, conventional generators are moved to their minimum generation levels to facilitate priority dispatch units provided this action does not endanger the security of the power system.
High Efficiency Cogeneration/Biomass/Waste to Energy	Biomass, Waste to Energy and high efficiency co-generation are afforded mandatory priority dispatch. Where there is no security threat to the system (as otherwise priority dispatch no longer applies) and a choice of priority dispatch units has to be made, this hierarchy is considered to be marginally more secure. This is because not utilising the CHP, biomass or waste to energy resource allows for it to be used later (as against wind, solar or tidal units where utilisation of the resource cannot be deferred) thereby increasing the security of supply of the system in a small way. A number of such units have internal processes which require them to run at a certain level of generation which needs to be considered.
Wind/Solar/Tidal/Hydro	Within the wind category there are subcategories reflecting the controllability of wind farms (wind farms that are controllable are given priority over wind farms that should be, but are not, controllable). Solar and Tidal generation were not included in the 2011 Decision Paper but where subsequently included in the hierarchy by the TSOs pursuant to a letter from the SEM Committee on 24 March 2017.

Interconnector schedules:	Interconnector schedules are an output of the ex-ante markets and are represented as fixed demand and/or generation profiles within the scheduling and dispatch process. These profiles may be amended using Cross-Zonal Actions.
Generation the dispatch down of which results in a safety issue to people arising from the operation of hydro generation stations in flooding situations:	Irrespective of the obligations to afford priority dispatch to eligible units, where there is a risk to public health and safety, this hierarchy will not be followed.

Table 6

Consultation Question 9: Do you agree with the TSOs' proposal for a revised priority dispatch hierarchy? The RAs request that the TSOs consider the points raised in this Section in their response with any further proposed changes to the hierarchy.

3.5 Priority Dispatch for certain new Eligible Units

As discussed, with respect to the removal of priority dispatch for new renewable generators (those commissioned after 4 July 2019), certain new renewable generation and demand-side facilities are excluded from these requirements, covering:

- New renewable energy generating facilities with an installed electricity capacity of less than 400kW. From 1 January 2026, priority dispatch will apply only to power generating facilities using renewable energy sources with an installed electricity capacity of less than 200 kW.

- Power-generating and facilities using high-efficiency cogeneration with an installed electricity capacity of less than 400 kW.

- Generators, energy storage facilities and other demand-side response units demonstrating innovative technologies, subject to approval by the regulatory authority with a limitation to such priority for the time and extent necessary for achieving the demonstration purposes; and

The Electricity Regulation defines a 'demonstration project' as '*a project which demonstrates a technology as a first of its kind in the Union and represents a significant innovation that goes well beyond the state of the art*'. Under Article 12, Member States should ensure that priority dispatch is afforded to demonstration projects subject to approval by the Regulatory Authority for a limited time period.

The RAs are seeking feedback as part of this Consultation on the types of demonstration projects that may be suitable for an application process for limited priority dispatch eligibility. The RAs' view is that such projects should be targeted and that an application process will need to be established to provide RA consent for such units to be eligible. This is also linked to the SEM Committee Information Paper on Balance Responsibility under Article 5 of the new Electricity Regulation (SEM-20-027) which also includes certain provisions for demonstration projects.

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

3.6 Cessation of Eligibility for Priority Dispatch

Article 12(6) states that priority dispatch shall no longer apply to power generating facilities '*from the date on which the power-generating facility becomes subject to significant modifications, which shall be deemed to be the case at least where a new connection agreement is required or where the generation capacity of the power-generating facility is increased'*

Connection Modifications are regularly processed by the TSOs and in many cases require a new connection agreement. The RAs are concerned that this may create a barrier to the repowering of existing wind farm sites for example and the implementation of the most effective use of network assets in terms of accommodating renewable generation and may introduce perverse incentives to avoid necessary or useful modifications where they introduce the requirement for a new connection agreement.

The Article clearly defines a significant modification to represent either or both of the following situations;

1. Where a new connection agreement is required.
2. Where the generation capacity of the power generating facility has been increased.

The implications of any loss of priority dispatch are likely to diminish as more generators are no longer eligible for such treatment, for example in the case of energy balancing actions taken by the TSO for non-priority dispatch units. This may have other implications for existing units with minimum generation requirements and the RAs welcome feedback on the interpretation of this point of the regulation and any mitigating measures that may need to be considered.

In addition, the Regulation provides for Member States to provide incentives to installations eligible for priority dispatch to voluntarily give up priority dispatch. The RAs do not propose incentivising units to give up priority dispatch in this Consultation Paper, however once the rules and systems are established to cater for priority dispatch and non-priority dispatch renewables, the RAs are of the view that units should be able to make a choice on whether they wish to retain their priority dispatch status or not.

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

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

4. Proposals for Implementation of Article 13

4.1 Redispatch in the Internal Energy Market and in the SEM

As discussed in Section 1.2, requirements for redispatching of generation and demand response are considered under Article 13 of the new Electricity Regulation. Redispatching is a central topic under the implementation of a number of European guidelines on Capacity Allocation and Congestion Management (CACM), System Operations (SOGL) and under the new Electricity Regulation as part of the Clean Energy Package. Under the new Electricity Regulation, ‘redispatching’ is defined as ‘*a measure, including curtailment, that is activated by one or more transmission system operators or distribution system operators by altering the generation, load pattern, or both, in order to change physical flows in the electricity system and relieve a physical congestion or otherwise ensure system security*.’

Under the Recital Section of the Electricity Regulation, it is stated that ‘*derogations from fundamental market principles such as balancing responsibility, market-based dispatch, or redispatch reduce flexibility signals and act as barriers to the development of solutions such as energy storage, demand response or aggregation.’* The RAs understand that the intent of Article 13 is to use market-based redispatching where possible and appropriate, with exceptions for the application of non-market based redispatching. Where there is a lack of effective competition and the presence of regular and predictable congestions, non-market based redispatching may be used.

In the EU context, redispatching is used across different Member States primarily for congestion management and is remunerated in a number of different ways. The most common method used is pay-as-bid pricing followed by regulated pricing based on either a market price (such as the Day Ahead price) or cost-based pricing (such as the remuneration of the cost of fuel and change in operating schedule of the plant).

ACER’s 2013 report[12] on the influence of existing bidding zones on electricity markets found that redispatching is increasingly used to solve congestion in larger bidding zones and is often

[12] Report on the influence of existing bidding zones on electricity markets: http://www.acer.europa.eu/Media/Events/ENTSO-E-and-ACER--workshop-on-the-Bidding-Zones-Review-Process/Documents/ACER%20Market%20Report%20on%20Bidding%20Zones%202014.pdf

organised in a non-market based way, with often limited competition in the redispatching market.

ACER's 2015 Market Monitoring Report[13] discussed the remedial measures applied by TSOs to relieve physical congestion on their networks, including redispatching. The report noted that the use of such remedial measures has increased in the EU due to the configuration of bidding zones (which is linked to Bidding zone review under Article 14 of the new Electricity Regulation), but also due to the increasing share of intermittent renewable energy production which is making the location of network congestions more dynamic and less predictable. The new Electricity Regulation also highlights the role of appropriately defined bidding zones in managing structural congestions.

In a report published in 2019 by CREG[14], the Belgian Regulator also noted the increased use and cost of redispatching in several countries in the EU, linked to the large scale integration of renewables in the market and coincident decommissioning of conventional power plants, which has had a large impact on congestion patterns. This is also a feature of the EU target model, which is based on implicit auctions for energy and transmission capacity in the ex-ante timeframe between bidding zones, with redispatching required in the Balancing timeframe in order to account for physically feasible dispatch.

As set out in detail in Section 1, in the SEM, a central dispatch system with ex-ante markets, the distinction between dispatching and redispatching is less intuitive as dispatching, energy balancing and redispatching all occur across multiple timeframes and there is no point at which dispatch ends and redispatch begins in the Integrated Scheduling Process. The RAs have interpreted redispatching in the SEM to relate to the reduction or increase of generation for both localised network and broader system reasons, including TSO-instructed reduction 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).

The RAs are of the view that in the case of the application constraints, as these take account of Commercial and Technical Offer Data submitted by Participants to minimise the cost of

[13]ACER/CEER Annual Report on the Results of Monitoring the Internal Electricity Markets in 2015, September 2016:
https://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/ACER%20Market%20Monitoring%20Report%202015%20-%20ELECTRICITY.pdf

[14] https://www.creg.be/sites/default/files/assets/Publications/Studies/F1987EN.pdf

diverging from PNs, in the SEM this is a form of market-based redispatch and is remunerated through Balancing Market Settlement.

In the case of curtailment, this is currently applied on a pro-rata basis to all non-synchronous units (as per the Decision in SEM-13-010) due to system-wide reasons and is not selected based on submitted bids of particular units. In the RAs' view this represents a form of non-market based redispatching. However, it is important to note that there are specific characteristics in the SEM in relation to curtailment that are not reflected in other EU Member States. The SEM is a market with a high level of renewable penetration in a weakly interconnected island context and the definition of curtailment used in the SEM is not the same as the definition used in other Member States, which mainly relates to constraints and congestion management. In addition, curtailment is not a defined term within the Regulation.

The power systems in Ireland and Northern Ireland are pioneering in relation to the high level of instantaneous renewable penetration (SNSP) managed, currently at 65%, with a target of over 90% by 2030. The higher the level of instantaneous renewable generation in the SEM, the greater the divergence will be between the ex-ante market schedule and physically feasible dispatch. This is discussed further in Sections 4.3 and 4.4.

4.2 Facilitation of renewable energy sources and high-efficiency cogeneration in redispatch

Under Article 13(4) of the new Electricity Regulation, TSOs and DSOs are required to report to the RAs on;

1. The level of development and effectiveness of market-based redispatching mechanisms for power generating, energy storage and demand response facilities;
2. The reasons, volumes in MWh and type of generation sources subject to redispatching;
3. The measures taken to reduce the need for the downward redispatching of generating installations using renewable energy sources or high-efficiency cogeneration in the future including investments in digitalisation of the grid infrastructure and in services that increase flexibility.

The RAs will be required to submit this report to ACER and publish a summary of this information with recommendations for improvement where necessary. The RAs intend to engage with the TSOs and DSOs in relation to the timing and structure of this report, noting that the TSOs currently produce an annual report on constraints and curtailment of renewable energy.

Article 13 of the new Electricity Regulation considers separate requirements for redispatching of units to those for dispatch under Article 12. Under Article 13(5)(a) of the new Electricity Regulation, TSOs and DSOs are required to guarantee the capability of transmission networks and distribution networks to transmit electricity produced from renewable energy sources or high-efficiency cogeneration with minimum possible redispatching. Network planning may take into account limited redispatching where the TSO or DSO can show that this is more economically efficient than alternatives and where redispatching does not exceed 5% of the annual generated electricity in installations which use renewable energy sources (unless renewable energy and high-efficiency cogeneration represents more than 50% of the annual gross final consumption of electricity). The RAs understand that the intention of this Article is to ensure than Member States transmit as much electricity from renewable energy sources or high efficiency cogeneration as possible with minimum redispatching. This is an important area which will need to be monitored and addressed through network planning, facilitation of system services and the DS3 programme.

Article 13(5)(b) states that TSOs and DSOs are required to take appropriate grid-related and market-related operational measures in order to minimise the downward redispatching of electricity produced from *all* renewable energy sources or from high-efficiency cogeneration, regardless of their commissioning date. In the RAs' view, regardless of the application of priority dispatch, this means that the TSOs should aim to minimise the application of constraints or curtailment in the SEM to renewable generators and HECHP.

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

4.3 Introduction of a non-market based downward redispatch hierarchy

As per Section 1.2 of this Consultation Paper, the RAs have interpreted non-market based redispatching in the SEM context as including the application of curtailment by the TSOs. Article 13(6) introduces a new hierarchy for the application of non-market based redispatch, entirely separate to the priority dispatch hierarchy considered in Section 3, which prioritises *all* renewable generators in non-market based redispatch (followed by high efficiency co-generation) regardless of their commissioning date.

Under Article 13(6) all renewable generators followed by high efficiency co-generation should only be subject to non-market based redispatch where other solutions would result in significantly disproportionate costs or severe risks to network security. The effect of this requirement in the SEM context depends on exactly how non-market based redispatch is applied now and in future. As the only form of non-market based redispatch in the current market arrangements is curtailment applied to non-synchronous generation, the main effect of this is to reinforce the provisions under Article 13 (5) to minimise the downward redispatching of electricity produced from *all* renewable energy sources or from high-efficiency cogeneration. This means that curtailment should be avoided unless other solutions would result in disproportionate costs or risks to network security.

This necessitates the introduction of a new hierarchy for the application of non-market based redispatch actions by the TSOs now and in the future, whereby they are applied in the following order (taking account of disproportionate costs, risks to network security and available solutions to resolve network and system issues);

1. Application of non-market-based downward redispatching to all classes of generation except renewable energy sources and high efficiency co-generation.
2. Application of non-market-based downward redispatching to high efficiency co-generation.
3. Application of non-market-based downward redispatching to renewable energy sources.

Consultation Question 13: Do you agree with the RAs' interpretation of Article 13(6) and the introduction of a new hierarchy for the application of non-market-based downward redispatching?

4.4 Curtailment in the SEM and Article 13(7)

In Ireland and Northern Ireland, renewable energy is currently predominantly sourced from wind, with other sources including hydroelectricity, solar photovoltaic, biomass and waste. Curtailment in the SEM refers to the dispatch-down of non-synchronous generation for system-wide reasons (where the reduction of any or all wind generators would alleviate the problem). There are different types of system security limits that necessitate curtailment:

1. System stability requirements (synchronous inertia, dynamic and transient stability).

2. Operating reserve requirements, including negative reserve.

3. Voltage control requirements.

4. System Non-Synchronous Penetration (SNSP) limit.

A number of operational issues which give rise to curtailment are being addressed by the DS3 programme. The System Non-Synchronous Penetration (SNSP) level, which is an indication of the maximum level of non-synchronous generation (wind and interconnection) which will be allowed on the system, was raised to 65% on a permanent basis in April 2018.

As noted in Section 4.1, the power systems in Ireland and Northern Ireland are pioneering in relation to the high level of instantaneous renewable penetration (SNSP) managed, with a target of over 90% by 2030. The level of curtailment per month in the SEM in terms of the percentage of generation in 2019 is shown in Figure 5 below, based on the TSOs' All Island Quarterly Dispatch Down reports. The last report published is for Q4 2019[15], which looks at the total amount of wind energy that is available but cannot be used by the system because of broad power system limitations (curtailments) or local network limitations (constraints).

[15] http://www.eirgridgroup.com/site-files/library/EirGrid/2019-Qtrly-Wind-Dispatch-Down-Report.pdf

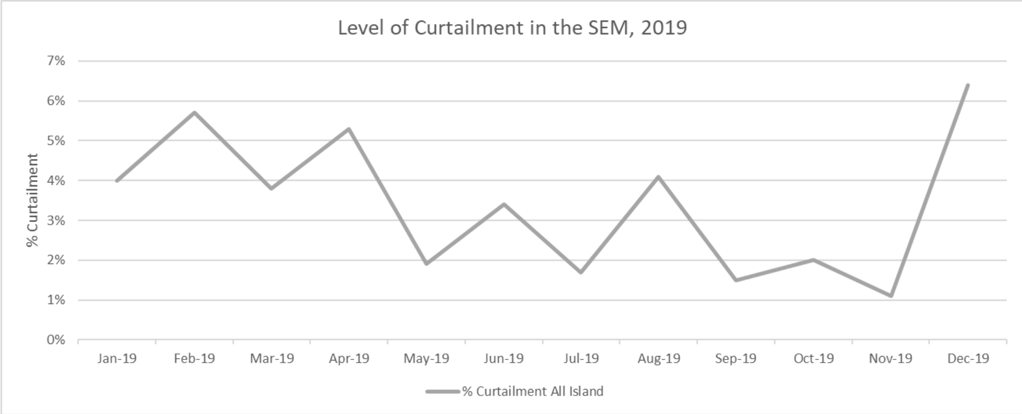

Figure 5

There are two reasons for the dispatch-down of wind energy; constraints and curtailment. *Constraints* refer to the dispatch-down of wind generation for localised network reasons (where only a subset of wind generators can contribute to alleviating the problem). *Curtailment* refers to the dispatch-down of wind for system-wide reasons (where the reduction of any or all wind generators would alleviate the problem). The SEM Committee approved the difference between constraints and curtailment in SEM-13-011 (included as an annex to SEM-13-010).

Under the current market arrangements, curtailment is applied on a pro-rata basis across all non-synchronous generation based on the principle of this being a system-wide issue not related to network and location specific issues. Under this approach, as each non-synchronous generator contributes to the system wide problem, each generator contributes to solving the problem. In SEM-13-010, the SEM Committee set out its view that pro-rata treatment was the fairest and most equitable methodology for the allocation of curtailment. The RAs are not minded to change the pro-rata treatment of curtailment as part of this Consultation Paper.

In addition, it is the RAs' view is that curtailment as a form of redispatch applies under Article 13 to all non-synchronous generation, regardless of whether or not such generators are eligible for priority dispatch or not under Article 12. On this basis, there is no distinction between old and new renewable generation under Article 13 for the purposes of the application of curtailment in the SEM and this does not introduce any prioritisation in relation to curtailment of priority and non-priority dispatch renewable generation.

Until the commencement of the revised market arrangements, compensation was provided for curtailment and was funded through Dispatch Balancing Costs. Under SEM-13-010, the SEM Committee decided to phase out payment for curtailment following an extensive consultation process. The SEM Committee's view was that as the level of wind connecting to the system increases, the level of curtailment may increase which if compensated would lead to a risk and cost to electricity consumers despite consumers not being able to utilise this electricity. In the SEM Committee's view, investment by consumers was better directed at the provision of system services and delivery of the DS3 programme in order to reduce the overall level of curtailment as much as possible. The SEM Committee noted in its decision that it is important to find the appropriate balance of risk between consumers and generators with regard to curtailment.

Article 13(7) requires that financial compensation should be provided by the System Operator to units with a firm connection which are subject to non-market based redispatching. It states that;

'*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.'

The RAs' interpretation of this, in the context of the SEM, is that under the current pro-rata curtailment regime, an appropriate level of compensation should be provided to curtailed generators, based on the higher of the additional operating cost caused by redispatching (for which non-synchronous units in the SEM currently have short run marginal costs of 0), or the net revenues from the day-ahead market including any financial support that would have been received under support schemes (such as REFIT, ROCs or RESS) (provided the financial support in question is linked to the amount actually generated). Where it is deemed that the level of financial compensation is unjustifiably high or low, compensation may be provided based on a combination of both elements.

The RAs are of the view that the balance of risk between consumers and generators, the utility of curtailed electricity and the limited funding available to invest in programmes to reduce the overall level of curtailment and facilitate higher levels of renewables on the system are important considerations in terms of the implementation of Article 13(7) of the new Electricity Regulation. The high level of instantaneous renewable generation in the SEM in comparison to the majority of EU Member States is also an important consideration here, along with the focus in the Regulation on congestion management rather than specifically on curtailment as it is defined in the SEM. The RAs' considerations in terms of the appropriate level of compensation to be provided by the System Operators in the case of non-market based redispatching are outlined in turn below.

1. There are specific characteristics in the SEM in relation to system wide curtailment that are not reflected in other EU Member States. The SEM is a market with a high level of renewable penetration in a weakly interconnected island context and the definition of curtailment used in the SEM is not the same as the definition used in many other Member States, which mainly relates to constraints and congestion management. In determining whether the level of compensation outlined in Article 13(7) is unjustifiably high the RAs are of the view that a comparative analysis of the treatment of curtailment in other jurisdictions is important. The Commission for European Energy Regulator's 2018[16] status review of renewable support schemes in Europe for 2016 and 2017 notes that '*Curtailments and compensation measures in case of congestions in the network are slowly moving into the focus of an increasing number of CEER Member countries*.' Annex 19 of the report provides an overview of RES curtailment schemes in the case of grid congestions in a number of Member States, which in many cases more closely relates to the definition of constraints used in the SEM rather than curtailment. In the SEM, curtailment occurs due to the high level of renewables and as a result of network constraints.

2. The power systems in Ireland and Northern Ireland are pioneering in relation to the high level of instantaneous renewable penetration (SNSP) managed, currently at 65%, with a target of over 90% by 2030 as part of the DS3 programme, which is designed to facilitate increased levels of renewables penetration in order to meet public policy objective. Any increase in SNSP over time will facilitate a lower level of curtailment in the SEM. There is a limit to the overall amount of funding available to the TSOs to invest in programmes to reduce the overall level of curtailment and

[16] https://www.ceer.eu/documents/104400/-/-/80ff3127-8328-52c3-4d01-0acbdb2d3bed

facilitate higher levels of renewables in the SEM (based on the level of network tariffs to recover costs from consumers). It is important to account for the total costs being recovered from consumers as part of the consideration of how this funding should be allocated, including investment in system services and the DS3 programme and an appropriate level of compensation for non-market based redispatching in the SEM.

3. One of the SEM Committee’s primary responsibilities is to protect the interests of electricity consumers on the island of Ireland. The SEM Committee expressed its view in SEM-13-010 that payments to non-synchronous generators for curtailed electricity represent a direct cost to electricity consumers, despite consumers not being able to benefit from this electricity. As more non-synchronous generation connects to the system, with an ex-ante market schedule which only accounts for interconnector constraints, consumers face increased costs and risk associated with the level of dispatch balancing costs (DBCs) 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. It is important to note that overall increases in redispatching across the EU and the costs associated with this are reflected in increased dispatch balancing costs for constraint management.

In addition, any compensation of curtailment up to the level outlined in Article 13(7)(b) needs to consider 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 which in 2019 were generally higher than the average DAM price based on the RAs’ analysis. This could lead to different compensation levels for different units based on their support scheme which would be difficult to administer within the Trading and Settlement Code and may have jurisdictional impacts in terms of costs.

The interaction of Article 13 of the Electricity Regulation with the Electricity Balancing Guideline Network Code (EGBL), Article 6 of the Electricity Regulation in relation to the Balancing market and procurement of balancing capacity is also important. The Electricity Regulation and EGBL require market-based procurement of System Services. This is based on the procurement and use of balancing capacity in an efficient, economic and market-based manner under the Electricity Balancing Network Code. The integration of the procurement of balancing capacity with the ex-ante and balancing markets and delivery of a competitive framework for the procurement of system services is currently being progressed by the RAs and TSOs. The current regulated arrangements for System Services are scheduled to end on 30 April 2023. The RAs are cognisant of the interaction between these two areas of work and the sequencing of implementation of the EGBL and CEP in the SEM. Further consideration is also required in terms of the difference between ex-ante market positions and physically feasible dispatch based on SNSP limitations.

The RAs are cognisant that the issue of certainty of investment and the provision of sufficient investment signals for renewable generation needs to be considered as part of this Consultation process at the implementation of Article 13(7) will affect the market remuneration of renewable generators and investment decisions.

The RAs have estimated the costs of providing compensation for curtailment of firm generators up to the level of support under Article 13(7)(b) based on the level of curtailment in 2019 on a monthly basis, shown in Figure 6 below.

The RAs have also conducted scenario analysis in order to estimate the potential cost of compensating for curtailment of firm generation over the next ten years as per Article 13(7)(b) based on the current levels of generation in REFIT 1 & 2 and ROCs support schemes, generation which is out of support, assumptions around installed wind and solar capacity over the next ten years, wind and solar capacity factors, the % of connected firm generation, levels of demand, DAM prices, new support such as RESS and a number of curtailment scenarios. This has been informed by the TSO's Generation Capacity Statement and Tomorrow's Energy Scenarios studies[17]. While this is based on a number of assumptions, depending of the level of curtailment (the RAs' scenarios are based on curtailment levels of between 5% and 10%), the RAs' analysis suggests that costs for compensation under Article 13(7) (b) could be between €40 million to €140 million per year.

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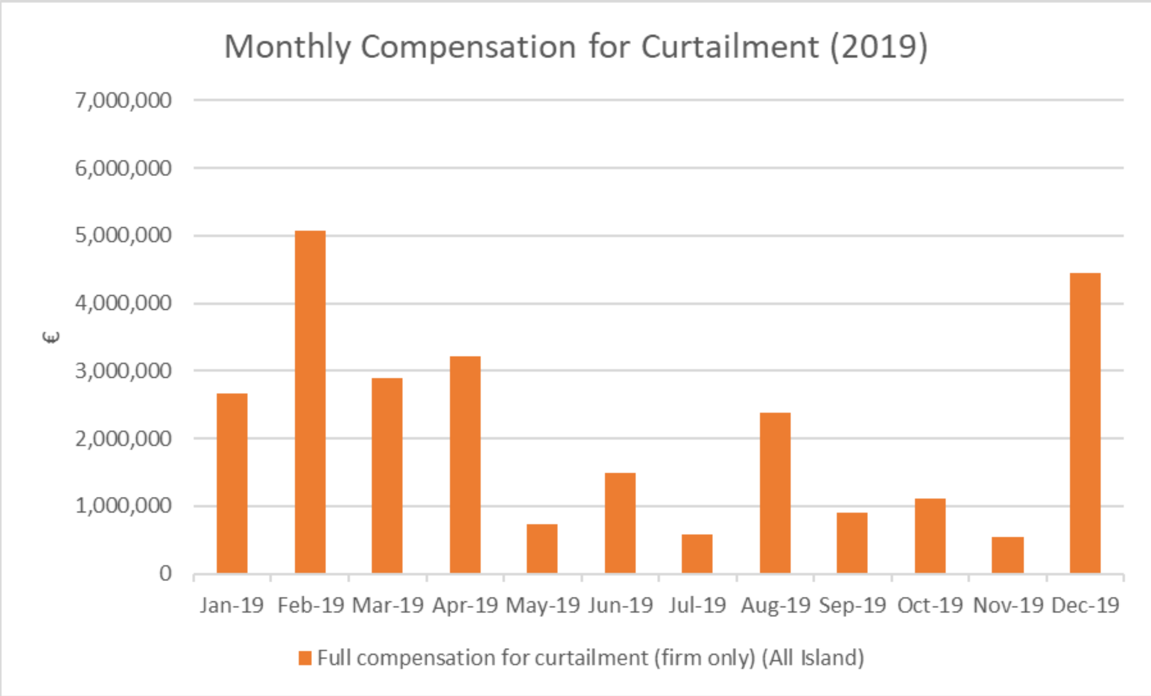

Figure 6

In the RAs' view, based on the principles and considerations outlined above, the provision of financial compensation to firm 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. As the level of non-synchronous generation on the system increases, the RAs consider that it is vital to focus on the appropriate changes to the energy market, system services and energy systems in order to facilitate high levels of renewables and reduce the overall level of curtailment, which will benefit both generators and consumers.

Article 13(7) allows for compensation to be provided based on a combination of the additional operating cost caused by redispatching (which is 0 for 0 marginal cost units) and the net revenues from the day-ahead market including financial support that would have been received where it is determined that applying only the higher of each would lead to an unjustifiably high level of compensation. Section 4.5 outlines the options the RAs are considering in order to ensure compliance with Article 13 (7) in a manner that is consistent with the objectives of decarbonisation and protection of electricity customers.

In setting out the options for implementation of Article 13(7), the RAs are cognisant of the need to ensure that generators which are in receipt of or have received support through public support mechanisms are not overcompensated. In the RAs' view, it is vital to ensure public funding is appropriately allocated in order to ensure a sustained energy transition and ensure that the burden on consumers does not become too great.

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

4.5 Options under Article 13(7)

Based on the considerations outlined in Section 4.4., this section describes a number of options for the implementation of Article 13(7). These consider potential options for the treatment of financial compensation for curtailment (as this represents non-market based redispatching in the SEM) from the System Operators based on a combination of the provisions under Article 13(7)(a) and 13(7)(b), on the basis that compensation based on the net revenues from the day-ahead market including financial support that would have been received represents an unjustifiably high level of compensation. As discussed in Section 4.4, the RAs estimate that this has the potential to cost between €40 million and €140 million annually based on the assumptions made in the RAs' scenario analysis.

Article 13(7)(a) relates to compensation based on the additional operating cost due to redispatching. In the case of non-synchronous renewable generation, this level could be as low as zero due to these units having a zero-marginal cost of production. The RAs have considered levels of compensation which range between this and net revenues from the day-ahead market including financial support that would have been received without any redispatching.

As noted in Section 4.4, non-market based redispatching in the SEM is related to and will be impacted by the implementation of the requirements under the Electricity Balancing Guideline in relation to the procurement of balancing capacity and the further development of System Services in order to allow the TSOs to manage a higher level of renewables on a sustainable and secure system. As implementation of the EBGL by the RAs is currently ongoing, the RAs are minded to consider an interim solution for implementation of Article 13(7) in order to be compliant with the Regulation and provide investor certainty to allow for a comprehensive approach to be developed in future which accounts for the implementation of EU Network Codes and other aspects of the CEP.

Article 13(7) relates to compensation for firm generators subject to non-market based redispatch and does not make any provision for compensation of non-firm generators. Firmness refers to the Firm Access Quantity (FAQ) of a generator connected to the system, which allows access to the network for a level of export capacity up to the limit of that FAQ. The RAs note that Connection Policy is a jurisdictional matter and is being progressed separately by the relevant Teams in the CRU and UR, however feedback is welcome in responses to this Consultation on the treatment of firm and non-firm connections in the market context.

The RAs are considering a number of options for the implementation of Article 13(7) for the Firm Access Quantity of generators subject to curtailment, outlined below.

Option 1 – Continue the Policy set out in SEM-13-010: Based on the considerations outlined in Section 4.4 concerning the level of compensation under Article 13(7) being unjustifiably high, the implementation of Article 13(7) could be aligned with SEM-13-010 by providing for remuneration only for the additional operating costs caused by redispatching (which is 0 for 0 marginal cost units).

Option 2 – Cap on Compensation linked to SNSP: The RAs are considering the option of applying a cap on the level of compensation for curtailment for firm generators which is linked to the overall level of SNSP, which mitigates some of the risk to consumers. As the level of SNSP is increased, the expected level of curtailment would be expected to decrease over time. As the percentage SNSP increases, the cap on compensation would also increase, based on the proportions in Table 7 below. The RAs estimate that the potential annual cost associated with this could be €40 million to €65 million for the SEM based on a 5% cap at an SNSP level of between 65%-75%, if generators are compensated up to the level of financial support schemes. It is difficult to estimate the potential level of costs associated with curtailment as the SNSP level increases. An alternative compensation mechanism under a cap linked to SNSP would be to compensate generators to the level of the day ahead market price.

% SNSP Level	Cap applied to % of curtailment subject to financial compensation
65%-75%	5%
75%-85%	10%

85%-95%	15%
100%	No cap applied

Table 7

Option 3 – Defined Cap on Compensation: A limitation of Option 1 is that SNSP is not the only reason for curtailment of wind, which may also be impacted by overall demand, levels of interconnection and minimum generation requirements for conventional generators. The implementation of a cap for compensation based on the applicable SNSP level may not correctly allocate risk between renewable generators and consumers. Article 13 (5) of the Electricity Regulation refers to the capability of TSOs and DSOs to transmit electricity from renewable energy sources with minimum possible redispatching, which should not exceed 5% of the annual generated electricity in installations which use renewable energy sources. On this basis, financial compensation could be provided up to a defined cap of 5% curtailment annually. The RAs estimate that the potential annual cost associated with this could be €40 million to €65 million for the SEM, if generators are compensated up to the level of financial support schemes. As per Option 1, an alternative under this option would be to compensate generators to the level of the day ahead market price.

Option 4 – Compensation only above a defined Cap: As an alternative to Option 2 and similarly based on the 5% redispatching target under Article 13(5), generators could be compensated for curtailment above 5% only. If the TSOs were required to compensate generators when levels of curtailment are above 5%, this would provide an incentive for the TSOs to limit the amount of curtailment on an annual basis.

Option 5 – Compensation based on a defined financial limit: Instead of a Cap on compensation up to a defined level of curtailment, this could be based on a defined financial limit for annual compensation for curtailment, which could be determined on an annual basis as part of the Imperfections Tariff setting process. The principles for how this annual cap would be determined would need to be developed but could be based on expected costs for a certain targeted annual curtailment level, a set proportion of overall modelled Dispatch Balancing Costs comparing the cost per MWh of constraints against a cost per MWh of curtailment or based on a cap set against historic costs in the SEM.

Option 6 - Move to market-based redispatch for curtailment: As discussed in Section 4.1, the RAs understand that the intent of Article 13 is to use market-based redispatching where possible and appropriate, with exceptions for the application of non-market based redispatching. Where there is a lack of effective competition and the presence of regular and predictable congestions, non-market based dispatching may be used. While the implementation of market-based redispatch for curtailment could not be implemented in the short term as it would represent a change to the tie-break rules and pro-rata treatment of curtailment outlined in SEM-13-010, the RAs are of the view that this merits further consideration in light of the broader requirements of the Electricity Regulation.

Option 7 – Consideration of the volume of redispatch rather than the price of redispatch: Options 1 to 6 above primarily focus on the costs associated with providing financial compensation for non-market based redispatching, rather than addressing the issue of the volume of non-market based redispatching in the SEM and the alignment between the ex-ante market schedule and physically feasible dispatch. Redispatching could be minimised by modifying how the TSOs operate the system, for example, but there may be other options for improving the alignment between the day-ahead, intraday and balancing market which the RAs welcome stakeholder feedback on. This could be linked to implementation of financial compensation as outlined in options 1 to 6 but would minimise the level of compensation required.

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

In addition to the options presented above, the RAs are cognisant that the requirement for financial compensation for non-market based redispatching under Article 13(7) came into force on 1 January 2020. As the determination of the appropriate level of compensation is an important part of this Consultation Process, the RAs also welcome feedback on when such changes should be implemented.

5. Conclusions and Next Steps

Responses to this Consultation Paper are invited until 22 June 2020 and can be provided to gkelly@cru.ie and Gary.Mccullough@uregni.gov.uk. During this 8-week consultation phase the RAs also intend to hold a series of meetings with interested stakeholders to discuss each of the elements raised in this Consultation Paper, invite early feedback from stakeholders and provide answers to any questions interested stakeholders may have in responding to the Consultation.

The RAs acknowledge that a number of complex issues are considered in this Consultation Paper and further workshops may be required as part of this process. The RAs also acknowledge that due to the range of issues considered in this paper, a further consultation or proposed decision process may be required before final decisions are made by the SEM Committee in relation to the implementation of Articles 12 and 13.