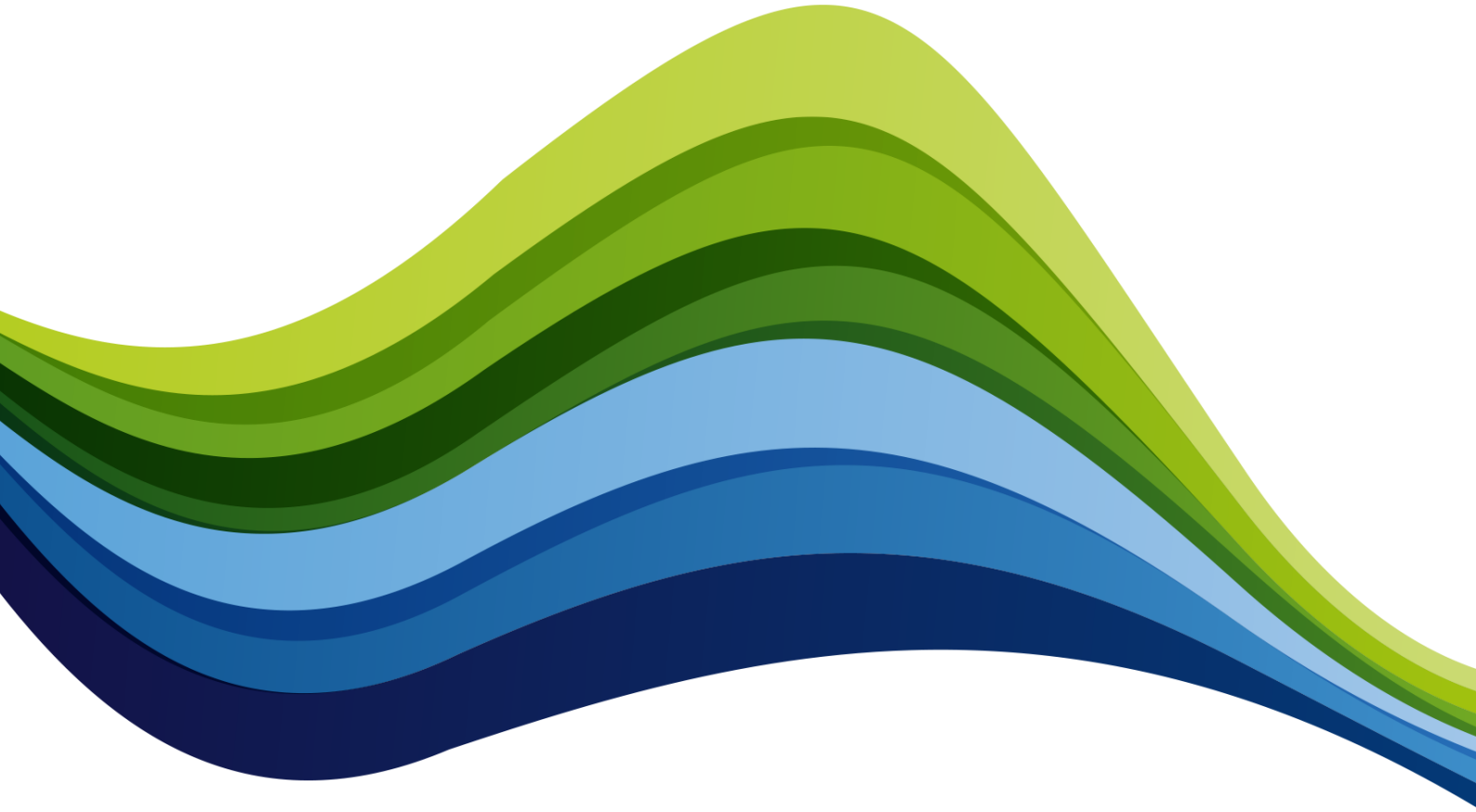
Implementation of Regulation 2019/943 in relation to Dispatch and Redispatch

SEM-20-028



Introduction

SSE welcomes the opportunity to comment on *SEM-20-028 Implementation of Regulation 2019/943 in relation to Dispatch and Redispatch*. For the avoidance of doubt, this is a non-confidential response.

SSE is a large generator operating circa 2,000MW of generation in the all-island centrally dispatched SEM. The Clean Energy Package contains a wide-reaching set of requirements impacting market design and the operation of both new and existing generation in the market. Most specifically, the treatment of redispatch, the future of priority dispatch; as well as the potential method for recouping the costs of implementation, i.e. imperfections etc.

SSE Response

SSE has provided both a general response and responses to the 15 consultation questions posed in the paper. We understand that Questions 2-11 relate to Article 12, and 12-15 to Article 13. We have provided a response to Question 1 on the interpretation of both Article 12 and 13. We have also participated in the drafting of the IWEA and EAI responses to this consultation and support the main arguments they present.

Under our general response we have provided comments on the following:

- Stakeholder engagement
- Implementation & delivery

Stakeholder Engagement

SSE welcomes the significant engagement that the RAs have undertaken with industry over the last number of weeks, to field questions and provide clarity on the context and background of this consultation. We would request that this approach continues during the course of development and implementation of solutions that will deliver compliance with Article 12 and 13. We acknowledge from discussions that the purpose of this consultation is to indicate areas we consider require further consultation, which we have clearly highlighted in our response below.

It is encouraging that a SEMO working group was established to facilitate discussion on the implementation of Article 12 into the SEM ("priority dispatch" working group). We advocate a similar working group is established to discuss the implementation of Article 13.

SSE would strongly advocate for a separate virtual workshop over the summer period to discuss the interactions between Article 12 and 13. This is an area we feel has received little attention to date, e.g. PSO, RESS, Connection Policy, imperfections charges and other interactions. We appreciate that everyone is working in a different environment given the pandemic situation, however, these requirements will span the full spectrum of market activities and will take some considerable time to interpret appropriately for our market. Industry needs a structured and consistent mechanism for collaboration and engagement.

We note that currently the SEMO working group exploring Article 12 implementation does not carry any agency with regard to the development of a solution. SSE would advocate that since this group was developed with the members of the Trading and Settlement Code Committee and observers as its original members, it should be able to assist in the development of a roadmap of specific code modifications and system solutions to implement Article 12. Furthermore, it should be the forum where SEMO can update industry on the progress towards interim or enduring solutions to the systems and provide opportunity to interrogate and test

the solutions being delivered. A similar role should be provided to a parallel working group considering the implementation of Article 13 within the ISEM market.

Implementation & Delivery

The consultation does not provide sufficient justification and confirmation that the proposals represent the optimal solutions to implement the various aspects of Article 12 & 13. The consultation implies the assumption that there is no significant change to the SEM High-Level Design or to current TSO processes and practices. We would advocate that the changes needed to implement the new requirements, require as much change on the side of the TSO and market design (if not more), than on the side of market participants, e.g. binding and transparent TSO processes that clarify the "significant modifications" that would trigger a loss of priority dispatch, or consideration of the approach to price takers as this segment of the market will reduce.

From the SEM-19-073[1], it was clear that there would be certain workstreams prioritised for implementation under the Electricity Regulation. Beyond this initial roadmap, it has been clarified at stakeholder bi-laterals with the CRU and at the SEMO priority dispatch workshop, that there is no roadmap for delivery beyond the current consultation. We consider that this significant shortcoming should be addressed as a priority; a roadmap must be developed including milestones, deliverables and specific activities (such as amendment to the Act), as well as a list of consequential modifications to the various Codes. We are happy to offer the RAs a proposal of the key areas, workstreams and deliverables that need clarity.

Furthermore, SEMO is clearly still at "whiteboard" stage where they have conceded they do not yet know what the problem is, that they are seeking to solve. This is unacceptable. The concept of the Clean Energy Package started to take shape before the establishment of the new SEM, and now with the Regulation in force, it is extremely concerning that there is no clarity on a roadmap for delivery of this work. There was significant industry analysis of the implications of the Clean Energy Package during the course of 2019 (e.g. forums held by EAI, IWEA, Mason Hayes & Curran). Preparatory work in cooperation with industry could have been initiated at this early stage of assessment, to clarify the starting positions and framing of the problems arising in the implementation of Article 12 & 13. Setting this aside, we hope that Regulators, industry and TSOs can work in an open and collaborative manner on what will be as significant a change to the market as the ISEM project was.

SSE requests that work to deliver Article 12 & 13 is prioritised and resourced accordingly, to ensure that there is no knock-on impact on the current operation of the market. We have pointed out in previous consultation responses that SEMO is clearly experiencing resource and delivery constraints as demonstrated by ongoing settlements delays. We note that these effects of insufficient resourcing are also being experienced in the accurate delivery of CRM auction process across 2019 and 2020, e.g. significantly delayed publication of registration and qualification forms. Therefore, for the implementation for Article 12 & 13 to be successful, resource requirements and priorities need to be scoped.

SSE also requests that there is sufficient engagement with industry during the development, scoping and testing of the system solutions. Specifically, that industry have an opportunity to participate in testing to avoid the issues we have experienced following SEM go-live. We note the specific situation with the system vendor which has an impact on how swiftly changes can be made and can "go live". This is regrettable and already a hindrance to the operation of the market, e.g. repricing functionality. This needs consideration in order to ensure timely implementation of EU 2019/943.

[1] https://www.semcommittee.com/publications/sem-19-073-roadmap-clean-energy-package-implementation

SSE appreciates that the RAs wish to see the industry responses to this consultation before charting a way forward. Given the high degree of ambiguity and unknowns in this consultation, it is not with any confidence that SSE can provide definitive responses to the RAs on any but a limited set of factors that relate to the implementation of Articles 12 and 13. This is not to be obstructive. It is clear to us that implementation of these Articles has wide-reaching and currently unknown implications on various related areas such as Connection Policy, PSO, RESS, constraints reduction, price control funding, imperfections charges, repowering or continuing locational constraints. Given this lack of clarity, it leaves SSE with very little room for blanket support of the SEM Committee's proposals. We would request acknowledgement of these complexities and the convening of further virtual stakeholder workshops with industry to cover the areas impacted by these requirements.

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?

SSE acknowledges the interpretation of the requirements under Article 12. We note the interpretation of the eligibility criteria raised in subsequent consultation questions below, risks widening the requirement under Article 12. We also note that under certain consultation questions, the proposed interpretation or effect cannot be considered without including the accompanying interaction of Article 13.

With regard to Article 13, we agree that market-based redispatch needs to take account of the commercial and technical offer data submitted by participants. As it stands, no priority dispatch unit is capable of submitting commercial or technical offer data needed to minimise the cost of diverging from an ex-ante schedule. Additionally, there is currently no ability for non-priority dispatch renewables to submit such data. In the absence of this capability in the market, all redispatch of renewable generation is necessarily non-market based.

There is confusion in the consultation as to what constitutes redispatch. Table 1 on page 16 of the consultation appears to indicate that only the real-time actions taken by the TSO are redispatch. It is not clear how this is in line with the definition of redispatch set out in the regulation which does not appear to restrict redispatch to only real-time decisions taken by the TSO.

Specifically, the regulation defines redispatch 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'*.

As it stands Physical Notifications (PNs) and commercial and technical offer data from priority dispatch units are not considered as part of the market solution, therefore both constraints and curtailment for these units must be non-market redispatch.

Article 13 clearly states that dispatching shall be based on objective, transparent and non-discriminatory criteria. It is not yet clear how the RAs are proposing to ensure that this requirement is implemented so as to allow all generation - regardless of priority dispatch status - to be able to participate in the SEM. This would appear to include permitting the submission of technical and commercial offer data for all units that are used to balance the system.

Finally, SSE notes that generators would be faced with an untenable situation if non-market based redispatch is deemed to be "too expensive", but at the same time there has been insufficient investment in grid reinforcement to reduce redispatch volumes. High volumes of redispatch will persist and will likely increase with higher degrees of non-synchronous generation on the system and lack of grid investment. This makes compensation for non-market based redispatch essential. The legacy of non-firm access rights also must be

considered as part of the discussion of compensation for redispatch given its reference in Article 13. SSE welcomes the recent ECP-2 decision in Ireland which has placed an obligation on the TSO to develop a methodology for Firm Access Quantities to be provided. This is likely to impact on the future build out of renewable generation necessary to meet climate targets. Therefore, SSE considers that until this methodology is consulted on and implemented, compensation for redispatch of all units regardless of firmness should be applied.

Taking account all of the above, it would therefore indicate that non-market redispatch includes both constraint and curtailment as understood in SEM. Given the impact this interpretation has on other sections of this consultation, in particular the implementation of Article 13, SSE is of the view that further consultation on this point is required from the RAs to clarify the interpretation of redispatch, as it applies to the SEM and the specific configurations of our market.

SSE response to consultation questions related to Article 12

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.

In general, we have concerns that the proposed criteria for eligibility proposed, broadens the scope of eligibility beyond what is clearly mandated under the Regulations. Furthermore, the rationale for additional eligibility criteria, where it is clearly indicated in the Regulations that there is a date criterion, is also unclear. We would suggest that justification for why additional eligibility criteria are needed, should be provided before industry agrees to additional criteria that may introduce unnecessary complexity.

We would not be in favour of the concept of relying on a commissioning programme agreed with the TSO. At the moment, commissioning programmes are not issued for all projects and therefore cannot be utilised as a consistent criterion for priority dispatch eligibility.

Equally, the use of a criterion based on *"eligibility to be processed to receive a valid connection offer"* is inappropriate as a measure of eligibility for retention of priority dispatch. The proposed criterion is indefinite and non-binding; i.e. whether a project could get a spot in the queue for likely receipt of a valid connection offer. This should not be the basis for demonstrating eligibility to retain priority dispatch, which is a key component of SEM market design. Use of such a measure adds unnecessary ambiguity to what is otherwise quite clear in the Regulations. The Regulations mandate certain requirements on specific generators based on the date criteria of 4 July 2019 and 1 July 2025. Finally, this proposed criterion would also encourage projects to hold their place in the queue in an effort to retain priority dispatch. SSE cannot support such a subjective criterion.

In principle, the use of a REFIT letter of offer or PPA are well-understood, defined and specific. Therefore, this is a suitable criterion to demonstrate eligibility on the basis that it will also align with the date criterion set out in the Regulations.

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.

SSE has engaged in the SEMO workshops discussing the implementation of Article 12 through an interim solution, before an enduring system change can be provided. The interim solution appears to suggest that where priority dispatch is lost, these units will be treated more like other dispatchable units. We take this to mean that submission of commercial and technical offer data and FPNs would be expected. It is important to emphasise that currently, INCs data cannot be provided. This needs to be factored into any consideration of how these units can be treated and can operate more like dispatchable plant.

For new generation, the loss of priority dispatch is understood to be an inevitability. However, the unacknowledged priority dispatch relating to locational constraints and must-run plant must also be addressed in order to ensure a completely level playing field in the SEM. For existing units, we appreciate that the intention is to consider the possibility that units can opt out of priority dispatch. We consider that this opt out must remain discretionary. In the current heavily constrained market with high degrees of dispatch down, there is a perception that the loss of priority dispatch will result in higher risk of redispatch of those existing units that would otherwise have the protection of priority dispatch.

A centrally dispatched system without priority dispatch also introduces complexities in a market with prevailing negative prices and a RESS scheme that does not provide support where there are negative prices. This must be considered, and a mechanism provided to help reduce exposure to negative prices.

Further discussion and consultation in this area should explore the following in the context of implementation:

- A mechanism for wind units to be able to bid themselves back and thus reduce their exposure to negative prices—as they can then signal that they do not wish to be dispatched at that time. We appreciate that self-dispatch to achieve this action, would be more difficult and conflict with the principle of central dispatch. It is important that there is a mechanism to control price at certain times for units that are no longer eligible for priority dispatch, as well as those specific units that decide to continue to rely on SEMO issuing "deemed PNs", despite no longer having priority dispatch status. In those latter circumstances, such a mechanism would need to allow for binding PNs to be submitted on occasion to allow those units to reduce their exposure through ultimately being dispatched down, without these submissions being overwritten by a "deemed PN".
- The same mechanism should be considered for both merchant units, (where they are forced to sell energy every day, even during negative prices and cannot self-dispatch down), as well as for units that retain priority dispatch, (since they will form a gradually reducing group of units that in a static dispatch hierarchy, will continue to be exposed to negative prices with no opportunity to bid themselves down due to the current approach of TSO forecast PNs being applied).

- Development of an opt out of priority dispatch on a discretionary basis. This appears to require changes to legislation as well as Grid Code and potentially High-Level Design as it also relates to the principles around price takers. Furthermore, the Regulations are clear that the opt out of priority dispatch could be incentivised in some manner. So far, there has been no consideration of how the loss of priority dispatch can be made an attractive option; e.g. creating an environment where units can bid themselves back, or where redispatch is addressed to a level that priority dispatch is not perceived as a protection against excessive curtailment in a heavily constrained market.
- The impact of Mod 10_19 *Removal of negative QBOAs related to dispatchable priority dispatch units from the imbalance price*[2]. This has been approved and is awaiting system release under Code Release F. Given the subject matter relates to priority dispatch, this needs to be considered as part of the implementation of the requirements of Article 12. We imagine there will need to be a similar consideration of any other relevant new code modifications, as well as changes to the existing version of the Codes.
- The interim solution suggested at the SEMO priority dispatch workshop will need to: define dispatchable plant differently if "deemed PNs" are still retained for some units, resolve how wind units can submit INCs and which system will be used (EDIL, Wind Dispatch Tool or a third option). An accompanying deadline for units to upgrade their systems will also need to be coordinated and signalled early, to allow units to be compliant in time.
- The registration of the previously non-dispatchable units as dispatchable, will also need to be clarified, i.e. if this is reregistration or change to registration.

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.

[2] https://www.sem-o.com/documents/market-modifications/MOD_10_19/Mod_10_19-DispatchablePriorityDispatch.docx

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.

It is assumed that the first part of this question is referring to the fact that if there is a deviation in volumes, these deviations for such a unit should be settled at the imbalance price; rather than for **any** volumes. On that basis, SSE can support this approach.

In general, the treatment of wind units as dispatchable units needs significantly more discussion and consultation to arrive at a solution that resolves the complexity involved.

For instance, the system burden for market participants in submitting greater levels of data and operating closer to a 24/7 operations desk must be considered. The RAs have confirmed that "deemed FPNs" were suggested as an option that could be retained for those smaller units who do not have the resources to provide this level of operations for their assets. This is welcome. It demonstrates that this burden is already acknowledged, at least for certain market participants. At the same time, this retained practice could create an unfair situation if it is not carefully considered as a temporary facilitation to allow a greater move towards a non-discriminatory market in line with Article 12. Therefore, it should have specific conditions attached to it, and a framework to help market participants over time move towards the market envisaged under the Regulations.

The uncertainty around which system would be suitable, i.e. EDIL, Wind Dispatch Tool or some other third option also still needs to be considered, as this relates to whether the proposal above of retaining "deemed PNs" is needed or can be avoided.

Finally, SSE notes the request for the TSO to provide a response specifically under this question. Therefore, in the absence of this response, there is not sufficient detail for us to be any more definitive in our response. This area would merit further discussion and consultation. As above, we would suggest that the solution for this question should be part of the SEMO priority dispatch workshop, which can also consider the TSC and system impacts of these changes.

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

In principle, it appears reasonable that these units continue to be treated as they are currently, in the market. However, it should be considered what criteria should exist for these units, to ensure that otherwise dispatchable units do not opt to re-register under this designation if it proves easier.

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?

There is not sufficient clarity as to how this will operate in practice, to be able to respond to this question. This may be the right course of action, but there is currently insufficient detail provided, e.g. how the cost of this action will be accurately reflected. This should be reviewed as part of a separate consultation on the dispatch hierarchy and methodology as impacted by Article 12 and 13.

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

SSE's interpretation of the consultation is that if a unit that loses priority dispatch it is to be treated as a dispatchable unit. Therefore, it is expected that these units would submit bids and offers like other units. However, as these units currently cannot submit this level of information, it is not known how the dispatchable category will fully impact these units and their bidding behaviour. This is also directly related to Article 13 and its implementation.

Therefore, it is not clear at this moment what would be a favourable principle or not, without an understanding of how this will be applied and will impact the relevant units.

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?

SSE recognises the need to have a tie-break solution for specific circumstances, but without clarity on the specific situations where a tie-break would apply and what rule is proposed, we cannot comment further. Therefore, we expect this would also be an area to be consulted upon as soon as a clear proposal is developed.

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.

As understood from the RAs bi-laterals with industry, a revised priority dispatch hierarchy is not yet confirmed. As noted by the RAs, the hierarchies in this paper also conflict and therefore this has raised confusion in the industry. On this basis, we expect that the dispatch hierarchy will require to be consulted on separately.

SSE expects there to be further response from the TSO as to what dispatch hierarchies may be possible. We note the interaction the dispatch hierarchy will also have with the tie-break approach in question 8 and redispatch hierarchy in question 13 and assume these need to be considered together. Finally, we expect some consideration of how the dispatch hierarchy may need to be flexed to reflect the implementation of the Regulations as a whole, i.e. beyond Article 12 & 13.

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

SSE has no specific comments in relation to this question. We would only note that for demonstration projects, there is a need to establish technology as being truly innovative and in need of pilot or demonstration status. Otherwise, where technology is already scalable, a framework to support entry into the market should be made available.

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.

In SSE's the definition of "significant modifications" that would necessitate the issuing of a new connection agreement lacks sufficient clarity in the SEM. Currently, even minor changes such as to Maximum Import Capacity will result in the issuing of a new connection agreement. In addition, the individual terms of a specific connection agreement appear to also be relied on as a trigger for when a new connection agreement may be required. This approach needs to change in order to drive a clearer understanding of what should trigger a new connection agreement in the context of Article 12.

The connections process and policy in other jurisdictions provides clarity such that generators can know what actions would result in a new connection agreements and what actions will result in an amendment to their existing connection agreement, on a universal basis. This is currently not the case in SEM.

The triggers for loss of priority dispatch are a key consideration for existing units who may wish to optimise generation at their site, but may avoid doing so, due to the risk of losing priority dispatch. Repowering and optimisation of existing sites is an efficient way to seek to optimise the grid and reduce unnecessary network investment. Therefore, a clear binding process for modifications should be facilitated and clearly outlined without undermining potentially valuable contributions to grid sufficiency.

We agree that generators should be provided the option to opt out of priority dispatch. We note that the Regulations indicate that incentives could be provided by Member States to encourage opt out of priority dispatch. Given the current heavily constrained market we operate in, and the reduced obligations enjoyed by non-dispatchable but controllable priority dispatchable units; opt out may currently not be an attractive option for many existing units.

SSE response to consultation questions related to Article 13

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.

The interpretation of redispatching is vitally important to being able to understand the current position of the RAs. It is SSE's view that further work will be required to set out and establish the interpretation of redispatch in the context of SEM. Section 1.2 sets out that redispatch includes any move away from PNs for generating units. In addition to this, those units which do not submit PNs or bids or offers in to the Balancing Market are subject to non-market redispatch, which would include any changes to the physical flows from the deemed PNs for wind/solar generation, regardless of being for system constraint or curtailment.

Subject to further consultation to define redispatch in the context of SEM, SSE agrees with the principal that downward re-dispatching of renewable generation should be minimised.

However, it is not clear yet how the RAs intend to meet the requirements of 13(5)(a) specifically with reference to re-dispatching not exceeding 5%. It is also important to ensure that focus is not lost on the requirement 13(5)(c) for network operators ensure that their networks are sufficiently flexible so that they are able to manage them in line with the Regulation.

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?

This needs to be read in conjunction with Consultation Question 9 to ensure consistency. This proposal would appear to reflect the requirements of the Regulation, however there is further consultation required over non-market based redispatch. As those units that are currently subject to priority dispatch do not submit bids and offers for the purposes of the balancing market and therefore all actions taken to change the physical flows of these units would then become non-market based.

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?

The Regulation is quite clear that where non-market based redispatch is used, a firm generator **shall** be subject to financial compensation.

"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."

Contrary to the position set out in the consultation paper, Article 13(7) requires compensation to be paid rather than "**allow** for compensation to be provided". It is up to the Member State to set out why this cannot be paid.

There is insufficient evidence in the consultation to support the modelling presented and therefore we are unable to comment on this in a meaningful way. It is SSE's view that the RAs are required to pay compensation, and in order to avoid paying compensation they must fully justify why the compensation is either too high or too low to market participants.

SSE considers that compensation based on the net revenues available from day-ahead market prices plus any financial support that would otherwise have been received, is the correct benchmark for compensation. Where this is deemed to be expensive it provides an incentive for TSOs to upgrade the network to reduce the cost of redispatch. Any deviation from

this principle risks eroding or eradicating the appropriate signal for network operators to make necessary investments.

Compensation for non-market redispatch should also be provided for non-firm generators to provide an efficient signal to the TSO in respect of incentivising efficient network upgrades and other work to minimise redispatch in line with Article 13. Failure to compensate non-firm generators for redispatch also risks undermining any progress towards developing an effective Firm Access Quantity methodology. Therefore, SSE considers that further work would be required, including a wide-ranging and thorough cost benefit analysis, before any alternative proposal could be properly considered for adoption.

Based on the consultation paper we are of the view that the RAs have not provided sufficient rationale or robust modelling to justify the proposed position. We therefore feel that it is incumbent on the RAs to carry out further studies on the potential impact and consult on the basis of those findings along with any modelling assumptions.

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?

There has been considerable work carried out to date that has contributed to reducing the deviation between the ex-ante market schedule and the physical flows on the network. SSE continues to support the work of both the RAs and the TSOs to enhance this further, to the benefit of the energy market as a whole and ultimately to customers.

SSE is of the view that Article 13 has the ability to reduce the risk, and therefore costs, of existing and future renewable generation. Implementation of Article 13(5), coupled with targeted and proportionate incentives on network owners and operators to deliver a network that can facilitate no less than 95% of available generation, will provide the most benefit to consumers. This will also reduce barriers to entry for renewable generators through the reduction of risk to revenue streams and ultimately benefit the consumer through efficient energy prices.

We understand the concerns the RAs have with regard to the potential costs associated with non-market based redispatch. It is also incumbent on the SEM Committee to have due regard to the ability of renewable generators to continue finance their activities. Looking at the potential costs in isolation does not take this into consideration and also fails to implement the requirements of this Regulation.

The proposals set out under Question 15 do not appear to fully implement the Regulation, nor do they accurately take account of the risks faced by developers. Some of the options presented here may have the unintended consequences of driving up the costs of renewable generation into the future, to the detriment of consumers.

SSE is of the view that options 1, 2, 3, and 5 are not in line with the requirements of Article 13 and we would not support the implementation of any of these options. We can see merit in developing options 4 and 6 further and using the full implementation of Article 13 as a comparator for a full consultation process.

SSE <u>does not support</u> the following options:

- Option 1: It is not clear how this option is compliant with Article 13 of the Clean Energy Package. Therefore, we do not think that it is possible to implement this proposal.

- Option 2: Places a cap on the level of compensation for curtailment only until SNSP goes above 100%. This has been justified on the basis of modelling that has not been made available as part of the consultation process and therefore cannot be sufficiently peer-reviewed. By only targeting curtailment, this option fails to provide for compensation for all non-market based redispatch that is required under Article 13.
- Option 3: This option does not appear to be in line with the obligations of the Regulation, in particular Articles 13(5) and 13(7). These specific clauses place an obligation on the TSOs and DSOs to minimise possible redispatching, such that it should not exceed 5% of the annual generated electricity from renewable generators. Capping compensation fails to address this obligation on the TSOs and DSOs. The impact of this is that it will expose the generators to the risk above 5%, which is contrary to the Regulation. Additionally, this approach fails to provide an incentive to the DSO/TSO to keep levels below 5%. For those reasons, SSE does not consider Option 3 as drafted, to be complaint with the Regulation.
- Option 5: This is very similar to Option 3 in applying a cap, but this time on a per MWh basis instead of an absolute basis. On that basis we do not consider this to be in compliance with Article 13.

SSE considers that the following options require further development and consultation to ensure they align with the requirements of the Regulation:

- Option 4: Is option appears to respect the provisions of Articles 13(7) in respect of compensation for all non-market based redispatch, whilst attempting to integrate the requirement of Article 13(5) such that no renewable generator should be subject to more than 5% redispatch. SSE is of the view that Article 13(7) should be implemented in its entirety. SSE considers that, provided this option sufficiently incentivises the TSOs and DSOs to reinforce the network and implement DS3 measures in a sufficient and timely manner, this option has the potential for further consideration. Further work is required to establish robust estimated costs of this option and the process for calculating both the level of compensation ex-ante, (through an assessment of the expected costs for the year ahead), and an ex-post adjustment to calculate the financial compensation that would be provided. Additionally, the final workable option would need to ensure that mentioned risks for developers are reduced so as to be able to provide value to consumers going forward. Finally, in order to be compliant with the Regulation, this option would also need to ensure that the compensation took into consideration all non-market based redispatch so that this was equivalent 95% of expected revenues. Without careful consideration and detailed consultation on how this option could work, this could place an undue administrative burden on the MOs and TSOs, to the detriment of consumers.
- Option 6: Further work is required to facilitate non-priority dispatch renewables within the market, in line with our response to the questions above. Whilst further work is required, SSE considers that option 6 attempts to implement the spirit of the Regulation. This option, subject to considerable consultation, has the potential to permit renewable generators to engage proactively in market-based redispatch provided that it was applied to all redispatch; both constraints and curtailment where the capacity is both firm and non-firm.
- Option 7: This option lacks sufficient clarity to be able to support or reject it. SSE is of the view that in any option Article 13(5) should be implemented such that the volume of redispatch is minimised. This is not a solution that can be resolved entirely through the energy markets and there is considerable overlap in the operation and development of grid infrastructure that will be required to meet the need of a low carbon energy system.