Energia response to SEM Committee Consultation on the I-SEM Capacity Remuneration Mechanism Detailed Design

Second Consultation Paper SEM-15-014

8 February 2016

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1. Introduction and Overview

This document sets out Energia's comments in response to the second Consultation Paper on the I-SEM Capacity Remuneration Mechanism Detailed Design, published 21 December 2015[1], including answers to the questions posed within that paper.

The remainder of this section 1 provides an overview of our key conclusions and discusses the governing legal framework and its implications for market design with a particular emphasis on issues pertinent to this Consultation Paper. Section 2 provides our comments to the questions consulted upon.

1.1 *Main Conclusions*

For convenience, we list our key findings and conclusions below.

- **Cross Border Participation:** None of the options for cross-border participation are without problems. However, to maintain consistency with the rationale provided by the SEM Committee in relation to the decision to implement a split market reference price (Option 4b), it is clear that cross border capacity providers (whether under an interconnector led or provider led approach) must be subject to the *same obligations to deliver* (into the market procuring the capacity) *at times of system stress* and be subject to the *same penalties for failing to deliver*. This is necessary (1) to ensure I-SEM providers are competing in a level playing field and (2) to promote the objective of security of supply.
- Only the 'Performance Based' variants for cross border participation have any prospect of meeting the above requirements. In fact, for reasons of undue discrimination, we do not believe that 'Availability Based' variants are in fact options that are available for I-SEM. Second, we also note that in SEM-15-103, the RAs have decided that mandatory bidding in the capacity auction will apply to dispatchable generators but will not apply to intermittent generation in I-SEM given the risks of participation[2]. Should the interconnector led approach be adopted despite its significant drawbacks, for the purposes of the capacity remuneration mechanism, there are no reasons to treat interconnectors and intermittent generators any differently. This means that they both should benefit from non-mandatory bidding but interconnectors should also have no other special privileges in the same way that intermittent generators are treated (i.e. the performance based variant applies).

[1] Consultation Paper "*I-SEM CRM Detailed Design Second Consultation Paper*", SEM-15-014, 21 December 2015.

[2] See CRM Detailed Design Decision Paper 1, SEM-15-103, published 16 December 2016.

- **Interconnector De-rating:** Interconnectors can guarantee very little by way of energy supply during system events, and their capacity must therefore be substantially de-rated for the sake of prudence.
- Historic interconnector performance in terms of physical availability, reliability and flexibility (including ramping constraints applied from a system operation perspective) is an important consideration that must be reflected in the de-rating and this should be interconnector specific. The vulnerability of interconnectors to long term outages caused by sub-sea cable damage should also be taken into account, as exemplified by the recent protracted Moyle outages.
- With respect to interconnector flows, it would be entirely inappropriate, not to mention imprudent, to de-rate the all-island interconnectors on the basis of historic flows. The design of I-SEM is intended to optimise interconnector flows. This should remove the currently pro-import bias to the all-island market, so that flows follow the energy price signals. Our modelling shows these flows to be primarily in the export direction (from the I-SEM to BETTA), contrary to the historic flows.
- Given the perceived conflict of interest, the regulatory authorities cannot delegate to EirGrid the task of devising a methodology for the de-rating of the interconnectors, however much EirGrid consults upon it. In this respect any decision made by the regulatory authorities that would be based on a methodology established by EirGrid would be tainted by objective, if not subjective, bias. The conflict of interest which would arise for EirGrid if tasked with developing de-rating factors applicable to the interconnectors cannot be addressed by ring-fencing, behavioral or transparency measures because these mitigation measures do not address the source of the conflict of interest, namely EirGrid's interest in the interconnectors (existing and future). This is the case regardless of the option that is selected by the regulatory authorities in respect of cross-border trading arrangements. The appropriate mitigation measure is in not giving the responsibility of the task of the de-rating of interconnectors to EirGrid but to assign that task to another independent third party under the control of the regulatory authorities.

- **Reliability Option Contract Duration:** Energia fundamentally disagrees with the proposal that only new entrants and re-furbished plants have access to longer term RO contracts. None of the reasons advanced by the regulatory authorities are in any way sufficient to justify such a fundamental difference in the treatment of capacity providers. Providing an advantage to new entrants is to unfairly discriminate against existing plants and distorts competition in the provision of capacity.[3]

- Promoting competition in the supply of capacity does not require the different treatment of existing and new plants, but addressing the market power that the incumbent operator ESB has on the market, in order to ensure that both existing and new capacity providers compete on a level playing field – i.e. implementation of effective, targeted market power mitigation measures to facilitate access to competitively priced risk management instruments and use of objective, fair and non-discriminatory criteria.
- Apart from the obvious and significant legal difficulties of discriminating between (or even defining) new and existing plant, we foresee a number of economic and practical difficulties with offering new entrants very long term contracts. The anomalous approach taken in GB, offering 'up to' 15 year contracts, offers no useful precedent for the I-SEM. Legally it is under challenge and internationally it represents a significant outlier.
- Discriminating in favour of new plant will only saddle consumers with higher costs than necessary. Moreover, precedents from other regimes, and consideration of the technological and economic risks facing investors, suggest that a shorter contract period is in order. For reasons of administrative simplicity and non-discrimination, we favour a model that offered shorter term contracts to all generators, bolstered by the promise of relatively stable (annual) contracts after those contracts end. Offering all participants (new and existing) the chance to compete for contracts of shorter duration (e.g. 3 to 7 years) will reduce risk and cost to consumers and will avoid discrimination. Should it be shown that conditions in the I-SEM require an even longer duration, we strongly recommend, based on our considerable investment experience, that there is no reason to extend ROs beyond 10 years.
- Similar legal, economic and practical issues summarised above apply equally in respect of DS3 system services contracts.

- **Secondary Trading:** Given the significant commercial risks imposed on CRM participants under ROs, which are heightened by the introduction of administered scarcity pricing, it is essential that a functional secondary capacity market is developed to enable participants to manage their exposure during planned or forced outages. In the absence of a functional secondary market, participants will have to manage these risks by

[3] Energia notes that the decision of the European Commission of 23 July 2014 approving the State aid to be provided by the UK to capacity providers, including longer contracts for new entrants, has been appealed to the General Court (see Case T-788/14 and also Case 793/14) on the ground, inter alia, that the discriminatory availability of longer contract durations cannot be justified by the legitimate objective of procuring the necessary amount of generation capacity.

significantly increasing the risk premium in their CRM bids. This is an imperfect hedge, potentially undermining recovery of missing money, and distorting CRM auction outcomes;[4] consequences that will undermine competition and increase costs to consumers.

- The I-SEM Market Power Mitigation (MPM) Consultation Paper (SEM-15-094) presented modelling results that indicate that ESB will be dominant or pivotal in the I-SEM capacity market until 2024 at least. The dominant or pivotal position of ESB will translate into additional market power in secondary markets for capacity, but this is not mentioned or analysed in either the MPM Consultation Paper or the current CRM Consultation Paper. This is a major omission that must be addressed.

Table 6-16: Summary of ESB structural market power metrics in the day-ahead market

Market participant	Capacity market share	Generation market share	RSI < 1.2 (% periods)
2016	44.4%	46.6%	9.1%
2019	46.1%	42.0%	12.5%
2024	52.3%	30.3%	37.5%
2024 (with additional I/C)	52.3%	26.8%	25.1%
2024 (with additional I/C and new gas-fired plants)	49.7%	25.7%	16.9%

Note: Capacity market shares exclude interconnection and wind capacity. Generation market shares include both GB imports and wind generation. The ESB generation market share includes an estimate of ESB wind output.

Source: SEM-15-094, p.62.

- Energia is particularly concerned about liquidity and market power issues in the secondary RO market given the small size of the I-SEM capacity market; the large proportion of the market likely to already hold ROs (especially given the mandatory nature of participation for dispatchable generation); and the dominant position of ESB within the I-SEM capacity market. More often than not, a generator looking to offset its exposure under an RO contract (e.g. due to a planned maintenance or forced outage) will need to trade with ESB, but ESB will not face the same commercial risks as other I-SEM generators, given it will own and operate the only large, fuel diverse generation portfolio in the I-SEM, which facilitates a significantly greater diversification of risk than is available to other participants, and consequently ESB will not be subject to the same incentives to trade.
- In light of the above it is essential that the RAs give careful consideration to issues of both market power and liquidity in the design and implementation of the secondary market for capacity, and implement

[4] For example, because the commercial risk profile of ESB under an RO scheme is significantly less than other I-SEM participants given their large, fuel diverse, generation portfolio.

appropriately targeted, liquidity promoting mitigation measures in the secondary capacity market (i.e. mandatory contracting obligations on dominant entities, such as ESB), as well as effective market power mitigation measures, to ensure there is adequate access for all CRM participants to competitively priced risk mitigation instruments.

- Energia would further note that failure to implement a functional secondary market in ROs has significant implications for other areas of the CRM design, including stop loss limits and the design of the administered scarcity function.

- **Administered Scarcity Price:** To avoid market failures, administered scarcity pricing tending towards VOLL (i.e. at GB VOLL) is only feasible *if the following requirements of risk management are met:*
  1) A liquid, transparent, exclusive and fully functional IDM to allow participants to appropriately manage exposure to energy imbalances;
  2) A liquid, transparent, exclusive, centralised secondary market for ROs, with appropriate and effective market power mitigation measures, including volume obligations on dominant participants, to allow generators to manage their financial exposures associated with planned and forced outages;
  3) A liquid, transparent, exclusive, centralised forward contract market with appropriate and effective market power mitigation measures, including volume obligations on dominant participants, to allow suppliers and generators to hedge their residual exposures up to the RO strike price;
  4) Exemptions from RO cash outs for generators that are available but not dispatched at times of scarcity;
  5) Appropriate stop loss limits to protect existing participants from bankruptcy and to remove potential barriers to financing for new investment.

- If the above requirements are not met by I-SEM go live then administered scarcity pricing that tends towards VOLL (even if set at GB levels) imposes large and unmanageable commercial risks on participants that could lead to potential market failures. There is therefore a strong impetus to deliver upon the above requirements given that the alternative (of not setting the administered scarcity price at a level at least equivalent to GB VOLL) has the following longer term implications:
  - Compromised security of supply, as the I-SEM could be exporting to GB at times of co-incidental scarcity;

  - Undermined effectiveness of the CRM design, as penalties for non-delivery under the RO scheme would be weakened; and
  - Negative implications for wider I-SEM energy market arrangements, including potential issues of revenue adequacy, given the prescriptive SRMC market power mitigation proposals being considered for the balancing market.

- However, on balance, and given our significant concerns regarding the delivery of appropriate risk mitigation instruments, including a functional secondary market, for participants across energy and capacity markets, Energia is of the view that transitioning from the EUPHEMIA price cap up to a maximum Full Administered Scarcity price, while a compromise, would seem sensible. The timing of this transition should be made contingent upon the successful delivery of the risk mitigation and market power mitigation measures outlined above.
- Significant stability in relation to the piece-wise linear function defining ASP (including the value of ‘X’ when ASP begins) is also needed.

- **Stop Loss Limits:** It is essential that the design of the I-SEM CRM achieves an appropriate balance between the desire for strong incentives under the RO scheme, the imposition of commercial risk, the overall level of that commercial risk, and the risk management instruments available to participants to manage their financial exposures. *Failure to appropriately balance these aspects of the CRM design could result in market failure.*
- It is therefore imperative that the design of the RO scheme ensures that CRM participants are provided with the appropriate risk mitigation measures to manage their exposure to RO cash out payments – i.e. a functional secondary capacity market, with effective market power mitigation measures, and appropriately set stop loss limits. *Failure to do so could lead to widespread insolvency issues.*
- It is also of vital importance that the design of the RO scheme does not unduly penalised CRM participants for non-delivery that is outside of their control (e.g. a result of dispatch / scheduling risk), as this would result in the imposition of unwarranted and unmanageable commercial risk. *Excessive and uncapped commercial risk will distort CRM outcomes, due to the lower risk profile of ESB under an RO scheme, and make it substantially more difficult to finance investment, therefore presenting significant barriers to new entry.*
- Energia therefore welcomes the decision to implement stop loss limits, which will provide a cap on the maximum level of financial exposure a participant would be exposed to under the CRM. We nevertheless observe that market power issues in the secondary capacity market, combined with the significant advantage conferred upon ESB under an RO

scheme, mean that other generation companies will face disproportionate, and higher, commercial risks when participating in the CRM. These risks are further escalated by the introduction of administered scarcity pricing. *This is therefore an extremely serious issue for competition in the wholesale generation market and requires very careful consideration.*

- Energia consequently recommends the following high-level characteristics are implemented in the design of stop loss limits. These will help to provide an appropriate cap on the financial exposures faced by participants, and offer some, albeit, limited protection, against potential exertions of market power.

  1) That annual limits are set such that the potential loss under an RO contract cannot be more than the revenue received – so if based upon a multiple of capacity receipts, this multiple is set at a maximum of 1. This will retain appropriately robust incentives under the RO scheme, while providing participants with at least some protection from excessive commercial risk, and exertion of market power. Energia note that at a VOLL Price of €10k, a single hour of forced outage during a scarcity event will cost a 400MW CCGT €4m; a figure that has significant implications for cash flow and bottom line profitability.

  2) We observe that the implementation of administered scarcity pricing significantly increases the requirement for a monthly stop loss limit. We therefore recommend that such limits are introduced, and their levels set appropriately to allow participants to manage their cash flow risk.

  3) That daily limits will be required if monthly limits are set too high.

- The stop loss limits proposed above however in no way undermine the need for the delivery of a functional secondary capacity market, or the other risk mitigation measures highlighted in this response.
- Energia further recommends that the detailed design of stop loss limits are consulted upon as part of the development of the CRM market rules, when the detailed design of the RO scheme will be more advanced, making it easier for participants to more accurately estimate their commercial risks.

- **Transitional Arrangements:** Option 3 from the consultation paper to "do nothing", is not a feasible option. It would lead to widespread disorderly exit from the all-island market, devastate investor confidence, and compromise security of supply.
- Energia believes there is a robust case for the RAs and the relevant government departments to push for measures, such as the 'Glide Path' option, that would help ensure an orderly transition to I-SEM.

- In the absence of the 'Glide Path' option, Energia therefore supports option 1 from the consultation paper, "auction each year separately", subject to their being sufficient time between auctions (we suggest a period of one calendar year, as per the T-1 calendar), to allow time to "iron out any teething issues" with the new I-SEM capacity market.

- **Commissioning window and implementation agreements:** Robust measures should be put in place to prevent 'ghost capacity' from entering the auction given the implications for security of supply and the criticality of capacity revenues to generators. It is also essential to the extent that providers do not deliver upon their contractual commitments that the capacity requirement in the T-1 auction is adjusted accordingly. This is not considered in the consultation paper.
- A number of questions in this section of the Consultation Paper cannot be fully or definitively answered at this stage and are best addressed through an industry Working Group convened by the RAs to cover the finer details of pre-qualification requirements, implementation agreements, and performance bonds.

1.2 *Legal Framework and Implications for Market Design*

Reference is made below to specific duties and obligations of the CER. We note that UREGNI, as the electricity regulator for Northern Ireland, has identical functions and duties as regards matters relevant to the Third Energy Package and the Single Electricity Market and its actions as an administrative authority is subject to similar general legal principles, and this section should be read accordingly.

As explained in Energia's response to the SEM Committee Consultation Paper "*I-SEM Market Power Mitigation*", a number of key legal requirements are particularly relevant to the design of I-SEM. They include, at the very least, the following provisions:

- **The objectives pursued under the Third Energy Package:** the measures adopted by the RAS must be consistent with the Third Energy Package and its objectives, namely, as regards electricity, the implementation of the internal market in electricity aims so as to deliver real choice for all consumers of the European Union and more cross-border trade, and achieve efficiency gains, competitive prices and a higher standard of service, and contribute to security of supply and sustainability. This means that facilitating cross-border trade must be done in such a way that it leads to further competition and the supply of electricity at the most competitive price.[5]

- **Directive 2005/89/EC** of 18 January 2006 concerning measures to safeguard security of electricity supply and infrastructure investment which requires Member States to ensure a high level of security of electricity supply by taking the necessary measures to facilitate a stable investment climate and by defining the roles and responsibilities of competent authorities, including regulatory authorities where relevant, and all relevant market actors and publishing information thereon. In doing so, Member States must take account of, *inter alia*, the importance of a transparent and stable regulatory framework and ensure that any measures adopted are non-discriminatory and do not place an unreasonable burden on the market actors, including market entrants and companies with small market shares. Under Article 5 of the Directive, Member Stets must take appropriate measures to maintain a balance between the demand for electricity and the availability of generation capacity, and in particular, must, without prejudice to the particular requirements of small isolated systems, encourage the establishment of a wholesale market framework that provides suitable price signals for generation and consumption.
- **The functions and duties of the CER under section 9 of the Electricity Regulation Act 1999**, which reflect the objective of fostering effective and sustainable competition. In particular, under section 9(1), the CER is responsible for ensuring, among other things, effective competition and the efficient functioning of the electricity markets and this requires the CER to monitor, among others "*the level of competition and transparency in respect of wholesale prices…*" It is also a duty of both the Minister and the CER under section 9(3) to carry out their functions and exercise their powers in a manner which does not discriminate unfairly between holders of licences and the ESB.
- **Section 9(4)(*a*) of the Electricity Regulation Act 1999** that requires both the Minister and the CER, in carrying out the statutory functions in Article 37 of the Electricity Market Directive, to have regard to the need, among others: (i) to promote competition in the generation and supply of electricity; (ii) to secure that all reasonable demands by final customers of electricity for electricity are satisfied and (iii) to secure that licence holders are capable of financing the undertaking of the activities which they are licensed to undertake.

[5] Recital 8 of the Electricity Directive, Directive 2009/72/EC

- **General principles of administrative and constitutional law:** public authorities such as the CER must act in a manner that is (1) consistent with the legal framework within which they operate and (2) reasonable.
- It is also a general principle of European law that measures adopted by a public authority should be proportionate, that is, any measure must be both *suitable* and *necessary* to achieve the aim pursued, so public authorities must choose the least onerous way of achieving that aim. The proportionality requirement also applies under Irish constitutional law.
- Where a measure affects a constitutionally protected right – such as the right to property or the right to earn one's livelihood, the implementing authority is under the obligation to ensure (a) that the measure is rationally connected to the objective and is not arbitrary, unfair or based on irrational considerations; (b) that the measure impairs the right as little as possible and (c) that the measure's effects on the right are proportional to the objective.[6]
- **European State Aid law requirements:** The I-SEM must be designed so that, in accordance with European law, including in particular State aid law, State intervention in the market is avoided to the maximum extent possible. The European Commission has made clear that State intervention through State resources for the purpose of ensuring sufficient capacity will not be deemed to be permissible State aid unless "*regulatory failures such as wholesale … price regulation*" have first been addressed and removed.[7]
- **The requirements of section 5 of the Competition Act 2002 to 2014 as well as Article 102 and Article 106 of the Treaty on the Functioning of the European Union having regard to the position of market power enjoyed in electricity markets by a State-owned entity, namely the ESB**: measures which do not properly distinguish between the position of (1) undertakings, in particular public undertakings, in a position of dominance on the market and (2) others would lead to unlawful discrimination. Similarly measures which do not recognise the special position of public undertakings and the possible differences in their incentives and consequent market behaviour would be incompatible with Articles 102 and 106 TFEU and Article 4 of the Treaty on the European Union.

These legal requirements apply to each and every measure that the RAs adopt or cause to be adopted in respect of I-SEM but also, importantly, to the package of regulatory measures which together will make up the I-SEM market design – including among others the Capacity Remuneration

[6] *Heaney v Ireland,* [1994] 3 I.R. 593
[7] European Commission, Communication of 5 November 2013, *"Delivering the internal electricity market and making the most of public intervention*", C(2013) 7243 final.

Mechanism, DS3 System Services, Administered Scarcity Pricing, energy market bidding restrictions, and other Market Power Mitigation measures. Key in this respect is the requirement that these measures, individually and taken together, allow generators to finance their activities, meaning that this whole package of regulatory measures must provide generators with an opportunity to cover their costs. In this regard, it is possible that the options preferred by the RAs in each of the streams for the I-SEM Design, because on their face they promote the objectives being pursued, are not together an optimal or indeed an acceptable or lawful combination. That is because together these measures may produce a result that is inconsistent with the Third Energy Package and the Electricity Security of Supply Directive and contrary to the requirement that generators should be able to finance their activities and be allowed enjoyment of their property rights. Measures that are under consideration by the RAs, including in particular prescriptive rules for SRMC pricing, directly and significantly affects the property rights of existing generators such as Energia and their shareholders. As participation in the market designed by the RAs is the only means available to existing generators such as Energia and its shareholders to exercise their property rights and right to earn a livelihood, it is incumbent upon the RAs, and essential, that the market design respects such property rights and allows a generator to recover its costs – any design which does not allow a generator to recover its costs, as would be the case where prescriptive bidding rules be adopted – would amount to a form of unconstitutional expropriation.

It is self–evident from the market design chosen and some of the market power mitigation measures consulted upon that there is a high risk of inefficient and inappropriate exit signals being generated from the combined I-SEM and DS3 revenue streams. This risk has arisen due to the obvious gap in the RA's thinking between design of revenue mechanisms that are largely based on a theoretical unconstrained market and the reality of the highly constrained electricity systems on the island of Ireland. Vague references to 'out of market contracts'[8] without follow up consultations or recognition in the project plan, do nothing to close this gap or reassure investors that a rational outcome will be achieved.

Below sets out by way of example a combination of measures which would not allow necessary generators to finance their activities and which as a result would be contrary to legal requirements and detrimental to competition and to

[8] "The SEM Committee has decided that, at this stage, the use of 'out of market' contracts should also remain open, and subject to further consideration within the market power workstream" (page 157 of I-SEM ETA Decision) and statement on page 8 of I-SEM HLD Decision (SEM-14-085a) that "the explicit CRM would work alongside any targeted contracting mechanisms that are put in place as a backstop measure to address security of supply concerns".

security of supply. We are particularly concerned that piecemeal consideration of individual measures might produce a combination like the following one:

a) Low prices in the Capacity Remuneration Mechanism, caused by failure to address e) below, and/or weak incentives to deliver capacity, and/or inadequate checks to ensure that offers of demand-side response are backed by the willingness and ability to reduce demand on request, and/or an overstated contribution from interconnector capacity, and/or special treatment of interconnectors or non-I-SEM capacity providers;

b) Insufficient DS3 System Service revenues, caused by the imposition of inappropriate cost-based tariffs or bidding restrictions, and/or a design which does not adequately remunerate services required and provided in real time (including from generators that are constrained on), and/or that unfairly discriminates against existing providers or that does not appropriately remunerate existing capabilities;

c) High Administered Scarcity Prices, imposing high penalties on existing capacity holders in the event of a shortfall, combined with the lack of institutions and rules necessary for them to manage the associated risks;

d) Illiquid secondary market for capacity, due to a lack of any obligation on ESB to make capacity available to others at a reasonable price;

e) Low, non-commercial offer prices submitted by a dominant, state-owned company like ESB as a result of insufficient properly targeted market power mitigation measures in the energy, capacity or system services markets;

f) Market power mitigation measures in the capacity auction, such as a "maximum exit price", which prevent capacity providers from bidding prices commensurate with the cost of the risks of holding Reliability Options; and

g) Overly prescriptive formulae that prevent generators from offering at all times prices sufficient to recover their costs.

Such a combination would expose generators to the risk of high costs if their capacity was unavailable during a shortage, whilst denying them the opportunity to earn the revenue needed to recoup their total costs. It would discourage both the construction of new generation capacity and the maintenance of existing generation capacity (including generation capacity required for system security). It would therefore threaten security of supply.

For the CRM Workstream, weak incentives to provide capacity, an overstated contribution from interconnector capacity (or the granting of special privileges to such capacity), *unmanageable* risks emanating from high administered scarcity prices, issues arising from State-owned ESB's dominance, and auction rules which prevent capacity providers from bidding prices commensurate with the cost of the risks of holding Reliability Options (items a), c), d), e) and f) above) are the most relevant. In the context of a capacity scheme that will be mandatory for dispatchable generators[9], the risks associated with holding Reliability Options will be imposed upon those generators unless they choose to close their plant. With reference to their statutory duties and relevant legal requirements, it is incumbent upon the regulatory authorities to ensure that such risks are reasonable and manageable so that all generators may compete in a level playing field and that those generators required to run the system are able to finance their activities. In practical terms, this means that the regulatory authorities must:

1. Ensure that generators are not held liable for RO difference payments when they are available, but not scheduled / dispatched by the TSO during an administered scarcity event.
2. Establish the institutions and rules required for a liquid, transparent, exclusive, centralised secondary market for ROs from I-SEM go-live to allow generators to manage financial exposures associated with planned and forced outages;
3. Place appropriate obligations on ESB to make secondary capacity available to others at a reasonable price (and other reasonable terms) on the centralised market from I-SEM go-live;
4. Ensure that the "maximum exit price" that will apply in the RO auctions does not prevent capacity providers from bidding prices commensurate with the cost of the risks of holding Reliability Options;
5. Apply properly targeted market power mitigation measures in the capacity auction to prevent low, non-commercial pricing by the state-owned incumbent.
6. Through consultation and modelling, determine appropriate Stop-Loss Limits (and other measures) to protect existing participants from bankruptcy, to remove potential barriers to new investment and encourage exit of unreliable plant.
7. Establish the institutions and rules required for a liquid, transparent, exclusive, centralised forward contract market to allow suppliers and generators to hedge their residual exposures up to the RO strike price;
8. Establish the institutions and rules required for a liquid, transparent and fully functional IDM from I-SEM go-live to allow management of energy

[9] As per CRM Decision Paper SEM-15-103.

imbalances and to help generators to trade themselves into the dispatch position required to manage their risks during scarcity events. (note that unless appropriate pre-notification of scarcity events is given, generators are still exposed to scheduling risk – see point 1 above) [10]

9. Review the Outturn Availability Decision (SEM-15-075), published 29 September 2015, and the firm access policy set out in the Building Blocks Decision (SEM-15-064), published 11 September 2015, having regard to the design of the I-SEM CRM to ensure that generators are Outturn Available and scheduled in a scarcity event, either via ex-ante or balancing markets, regardless of network outages;

[10] CRM Decision 1 (SEM-15-103) states that "Generators can manage [scheduling] risk by trading in the IDM to ensure they are dispatched against a deliverable profile and are in position to deliver their RO commitment" (paragraph 4.3.20). A similar statement was made by the RAs' representatives at the CRM2 workshop in Dundalk on 20 January 2016. It is important to recognise that the IDM in I-SEM will be opened in parallel with the BM (which is unusual) and when combined with market power issues (given the large retail and generation market share of ESB) could well result in liquidity issues in this market. Irrespective of liquidity problems in the IDM, we cannot stress enough that if notice of a potential scarcity event is provided to the market after a generator's notice time then that generator will not be able to trade into a dispatch position in time for the scarcity event via the IDM. It is therefore fundamentally important to ensure that generators are not held liable for RO difference payments when they are available, but not scheduled / dispatched by the TSO during an administered scarcity event.

2. List of Consultation Questions

For ease of reference, we set out below the list of questions in the Consultation Paper and our response to them.

2.1 Interconnector and cross border questions

General comments

Energia notes the SEM Committee's reasoning for adopting a split market reference price (Option 4b) for reliability options, notably how it promotes the I-SEM objectives better than the alternatives in the following key respect:

"**Security of supply**: it better promotes the objective of security of supply by ensuring that only reliable capacity is rewarded, and unreliable capacity *which fails to deliver at times of system stress* will be penalised"[11] (our emphasis)

The Decision Paper further provides a detailed account of how Option 4b better promotes the SEM Committee's objectives than Option 3 (a day ahead market reference price) with respect to security of supply (paragraphs 3.3.52 to paragraphs 3.3.55); this is worth recounting in full:

> "3.3.52 The introduction of Administrative Scarcity Pricing in the energy market goes a significant way to incentivising any capacity provider that can make its capacity available at times of system stress, to make its capacity available to earn the scarcity price. However, Option 3 permits a gaming opportunity for unreliable generators.
>
> 3.3.53 A key concern is that Option 3 would allow generators with unreliable capacity to bid into the auction, obtain capacity payments and pursue strategies to avoid any adverse consequences when they do not deliver. In effect this would be a free bet for generators who could profit from low cost "iron in the ground".
>
> 3.3.54 If a generator knows that it cannot deliver on its capacity obligation and does not bid into either the DAM or the BM then Under Option 3, the generator:
>
> - Is not at risk from having to buy back generation outages at high BM prices in the event of scarcity; and
> - Will not be materially exposed to RO difference payments, since international experience suggests that scarcity rarely if ever happens in Day Ahead timescales, the DAM price will rarely if ever exceed the RO Strike Price.
>
> 3.3.55 By contrast, a generator pursuing this strategy under Option 4b would be heavily penalised in the form of RO difference payments

[11] I-SEM Detailed Design CRM Decision 1, SEM-15-103, 16 December 2016, paragraph 3.3.42

settled against the BM, which reflects scarcity, without having any offsetting BM revenue."

To maintain consistency with the rationale provided by the SEMC in relation to the decision to implement Option 4b, it is clear that cross border capacity providers (whether under an interconnector led or provider led approach) must be subject to the same obligations to deliver (into the market procuring the capacity) at times of system stress and be subject to the same penalties for failing to deliver. This is necessary (1) to ensure I-SEM providers are competing on a level playing field and (2) to promote the objective of security of supply.

With the above in mind, we provide a brief assessment of the options proposed in the Consultation Paper for cross border participation.

Net Demand

This approach is very simple, but denies capacity outside the I-SEM any access to the CRM. Although the UK adopted it for the first capacity auctions in 2014, pressure from the European Commission forced it to switch to another system, which allowed interconnectors to participate. It is likely that the I-SEM would only be able to adopt the Net Demand approach as a temporary measure (as in the UK), if at all, given the launch of the State aid guidelines for energy and environmental aid and subsequent State aid inquiry into capacity mechanisms.

Interconnector Led

In principle, allowing interconnectors to obtain capacity obligations could provide incentives to invest in interconnectors. That does not increase security of supply per se; the effect on security of supply depends on the behaviour of energy traders, the likelihood of a system stress event (in both markets), and a host of operational codes and regulatory interventions. Thus, although it may seem superficially appealing (judging by the review in the Consultation Paper and given its adoption in GB), this approach is not fully coherent in economic terms. Furthermore, in the context of the I-SEM, it requires special (i.e. discriminatory) measures to overcome the resulting problems that would not be acceptable to I-SEM capacity providers.

The owners of interconnector assets are TSOs and are prohibited from engaging in the trade or supply of electricity under the Third Directive. They are therefore unable to act as independent providers of capacity in the conventional sense, i.e. as market participants able to commit to provide energy at times of system stress. The proposals in the consultation paper therefore suggest a number of special arrangements to make the scheme acceptable to the interconnector owners.

In paragraph 2.4.8, the Consultation Paper notes that the interconnector asset owners "would not receive payments from the I-SEM energy market necessary to cover the difference payments in the event that the Reliability Options were called" and observes that the lack of such revenues would expose interconnectors to major financial risks, if they had to make difference payments on the same basis as other holders of ROs (i.e. under the "performance based approach").

As an alternative, the Consultation Paper suggests an "availability-based" approach such that interconnector owners might only be obliged to make their capacity available, regardless of any flows over it. That would mean that the interconnector asset owners were protected against the possibility that electricity did not flow from GB to the I-SEM at a time of system stress within the I-SEM.

The rationale for the availability-based approach is the lack of control that interconnector asset owners have over energy flows and the risk that electricity might not flow because of operational or commercial factors within the GB electricity market. However, generators within the I-SEM who hold an RO could be subject to the risk that their plant is not despatched (e.g.because the stress period is too short, or comes at too short a notice) to facilitate the economic despatch of their plant. The interconnector asset owners would therefore be granted a special privilege if an availability based approach was adopted.

Moreover, the lack of any penalty for failure to deliver energy at times of system stress means that *interconnector asset owners would not in fact be committing to deliver capacity to the I-SEM*. As the Consultation Paper points out:

"2.4.13 This option would means that interconnectors receive the options fees in the I-SEM CRM up to their full de-rated capacity and hence would incentivise further investment in cross border transmission capacity but in effect passes the risk of non-delivery to consumers."

Thus, under the Interconnector Led, Availability-Based Approach, the revenue that interconnector asset owners would receive from ROs would in practice just be a subsidy from consumers towards the construction of interconnectors – a subsidy that might not even make any contribution to system security.

FTR Led

There are similar issues under the FTR approach as under the interconnector led approach including difficulties associated with making the holder of an FTR accountable for the actual energy flowing over the interconnectors at times of system stress. The suggested solution – to only require FTR holders to pay difference payments in the I-SEM at the day-ahead stage (effectively meaning that this approach becomes availability based for the intra-day and balancing market timeframes) is unacceptable, on similar grounds to those discussed in relation to the availability based interconnector led option – i.e.

discrimination against I-SEM capacity providers. It would also fail to promote the SEM Committee's objectives relating to security of supply in exactly the same way that Option 3 failed to do so according to the assessment in paragraphs 3.3.52 to paragraphs 3.3.55 (quoted above) of Decision Paper SEM-15-103. Another major problem with the FTR led approach is that FTRs would not be available at the time when ROs for that year are auctioned because of European regulations.

Provider Led

The provider led approach allows "non-I-SEM participants" to enter the CRM auction with capacity that (1) is physically located outside the CRM; and (2) can show there is a physical path from their capacity to the I-SEM electrical system. This approach requires some commitment to delivery within the I-SEM to receive I-SEM capacity revenues. However it seems extremely problematic to implement given the need to verify that the commitment to deliver has been fulfilled. The "availability based" variant of this approach is an attempt to address these practical issues associated with the provider led option, although we note it would still require implementation of bidding obligations compliance with which may not be verifiable or enforceable cross-jurisdictionally, but regardless, it would amount to non-ISEM capacity providers receiving a special privilege in relation to their treatment under the I-SEM CRM.

This model is presented as some kind of zonal CRM auction. Purchases of capacity from abroad are limited by the capacity of the interconnector (which has to be defined). If the supply of foreign generation capacity exceeds that interconnector capacity, it is rewarded with a lower price in the auction (lower RO revenue). This is seen as a benefit to customers, but is really just an expropriation of the revenue that would otherwise accrue to the owners of the interconnectors (who own the scarce capacity). The "hybrid" approach seems to be an attempt to remedy this deficiency.

Hybrid

This model is the same as the provider-led model, as far as external ("non-I-SEM") capacity providers are concerned. However, it would allow the interconnector asset owner to bid their capacity into the CRM auction and to keep the difference between the I-SEM RO price and the external RO price (paragraph 2.4.33). The external capacity providers would also be responsible for difference payments based on their respective contributions, as measured by availability (bidding into the market) or performance (flows over interconnector) (paragraph 2.4.33).

This option is intended to give interconnector owners an incentive to build more capacity. However, it "splits the revenue for cross-border capacity between external providers and the owners of the physical interconnectors" (paragraph 2.4.34), so the proposal includes measures to protect external capacity providers from the consequences when electricity does not flow into the I-SEM at a time of system stress. They would not have to make any difference payments when:

- "There is a shortfall in energy imported to the I-SEM (such that import is less than the Non-I-SEM capacity contracted through Reliability Options); and
- That shortfall is a direct result of a technical failure on one or more of the interconnectors linking the I-SEM to an adjacent market." (paragraph 2.3.34)

This approach effectively gives external capacity providers a "non-firm" RO, such that they are exempted from their obligations if there is a technical failure on the (cross-border) line connecting them to the I-SEM. (A failure in the own generation plant would not invoke the exemption.) The equivalent for generators within the I-SEM would be an exemption if they were prevented from generating at a time of system stress by a technical fault in their connection to the transmission network. Energia notes that this would not in fact constitute equal treatment for I-SEM capacity providers by virtue of recent SEM Committee Decisions on Outturn Availability (SEM-15-075) and the treatment of compensation for constraints under I-SEM (SEM-15-064).

1) Which of the approaches to the treatment of cross border capacity do you prefer and why? (For the Provider Led and Interconnector Led approach, please specify whether you prefer the "Performance based" or "Availability Based" variant).

As discussed extensively in our general comments to this section, none of the options proposed for cross border participation are without significant problems.

Energia notes that the discussion of the interconnector-led options overlooks the fact that interconnector asset owners do not actually contribute capacity. Because interconnector asset owners are ineligible to trade in electricity, the RAs propose special methods of measuring their contribution to total capacity, to exempt them from the consequences of failing to deliver. That represents a major difference from the treatment accorded to generators within the I-SEM that has no justification, since it does not help to secure any additional capacity (i.e. it may encourage construction of interconnectors, but does not encourage the supply of energy at times of system stress). The other options are also problematic but some at least recognise the need for offers of capacity to contain an element of electricity trading.

Furthermore, Energia observes a number of the options and proposed features raise very serious concerns because contrary to the fundamental principle of equal treatment, and the requirement of non-discrimination, these options involve treating the same, operators which are in a different position, or treating differently, operators which are in fact in the same situation. In addition to such approaches being unlawful for this reason and contrary to section 9(3) of the Electricity Regulation Act, the discriminatory treatment of capacity providers does not allow for the level playing field necessary to the development of competition, contrary to the requirement that the regulatory authorities promote competition in the generation of electricity.

More specifically, first, ***we do not believe that Availability Based variants are in fact options that are available for I-SEM.*** This is because with these variants, contrary to other participants, interconnector owners or non-I-SEM capacity providers would earn RO revenues merely for remaining available (availability-based monitoring). There are no objective reasons why this should be the case and therefore these variants are unjustified and discriminatory, and therefore unlawful. In particular, availability based variants are not capable of promoting competition while avoiding discrimination, consistent with legal requirements. Only the 'performance based' variants for cross border participation can ensure I-SEM providers are competing on a level playing field[12]

Second, we also note that in SEM-15-103, the RAs have decided that mandatory bidding in the capacity auction will apply to dispatchable generators but will not apply to intermittent generation in I-SEM given the risks of participation[13]. ***Should the interconnector led approach be adopted despite its significant drawbacks (as discussed under general comments above), for the purposes of the capacity remuneration mechanism, there are no reasons to treat interconnectors and intermittent generators any differently.*** This means that they both should benefit from non-mandatory bidding but interconnectors should also have no other special privileges in the same way that intermittent generators are treated. As intermittent generators, interconnectors will also (1) have a small share of de-rated capacity (see response to question 2 below) and (2) face additional risks under mandated bidding, due to their lack of control over the direction of energy flows, and hence over their contribution to capacity, at times of system stress. Interconnectors therefore fulfil the same conditions as those set out in paragraph 4.3.26 of SEM-15-103 for intermittent generators and must (should the interconnector led approach be adopted) be treated the

[12] Although the Hybrid option, which exempts non-I-SEM generators from their obligations to generate when prevented from doing so at a time of system stress due to a technical fault in their connection to the transmission network, would still amount to a material inequality compared with I-SEM generators and this would have to be remedied by reviewing the Outturn Availability Decision (SEM-15-075) and the Building Blocks Decision (SEM-15-064), having regard to the design of the I-SEM CRM to ensure that generators are Outturn Available and scheduled in a scarcity event, either via ex-ante or balancing markets, regardless of network outages.

[13] See CRM Detailed Design Decision Paper 1, SEM-15-103, published 16 December 2016.

same to avoid discrimination and the distortion of competition in the capacity markets (i.e. the performance based variant applies).

2) Should the de-rating of interconnectors be based on historic performance, or include forward modelling to project how its performance could change in the future?

We presume that 'historic performance' relates to past interconnector flows at times of system stress and the interconnectors' physical availability, reliability and flexibility.

Historic interconnector performance in terms of physical availability, reliability and flexibility (including ramping constraints applied from a system operation perspective) is an important consideration that must be reflected in the de-rating and this should be interconnector specific. The vulnerability of interconnectors to long term outages caused by sub-sea cable damage should also be taken into account, as exemplified by the recent protracted Moyle outages.

With respect to interconnector flows, it would be entirely inappropriate, not to mention imprudent, to de-rate the all-island interconnectors on the basis of historic flows. This is because such flows are distorted by the misalignment between the SEM and BETTA markets. Specifically, the SEM is an ex post market with outturn capacity payments paid to interconnector flows and SMP payments that are only known by participants after the commitment to trade has been made. Cash out against SMP therefore exposes traders to unknown, unpredictable, volatile and significant price exposures. These exposures, linked to the ex-post pricing mechanisms in SEM, create commercial risk that leads to a strong bias towards importing from BETTA to SEM[14]. The dominant direction of flow has indeed been from BETTA to SEM despite outturn price differentials in the opposite direction. However, the same conditions will not pertain under I-SEM and the relative level of market prices in BETTA and the I-SEM will directly determine the direction of flow on I-SEM interconnectors. This is because the design of I-SEM will remove capacity payments from IC flows and prices will be set in advance. ***Therefore, current interconnector flows in the SEM would provide an extremely misleading guide to future likely flows.***

[14] To explain further, the main reason for this import bias is the need for flows to be scheduled on the basis of forecast prices day ahead, whilst SMP, the price received/paid by these flows, includes a volatile Uplift component. Uplift can cause very high prices in SEM and is very difficult to forecast. If an Interconnector User gets scheduled at the day ahead stage to export based on its forecast of prices, they face the risk that some generator plant is called in one half-hour over this trading day. That plant needs to recover its cost through the Uplift mechanism, which would result in an extremely high price in this half-hour. Any Interconnector user that was exporting at that time would have to pay this price and would incur a very large loss. This exposure to unpredictable price risk deters Interconnector Users from exporting to BETTA, even when the price forecasts indicate that they should.

The design of I-SEM is intended to optimise interconnector flows. This should remove the currently pro-import bias to the all-island market, so that flows follow the energy price signals. In current conditions, our modelling shows these flows to be primarily in the export direction (from the I-SEM to BETTA), contrary to the historic flows. ***It is imperative therefore that the de-rating of interconnectors be informed by detailed energy market modelling with the objective of estimating prudent de-rating factors for future and existing interconnectors taking in to account the risk of subsea cable damage.*** In this context, it is appropriate to assume that interconnectors may add to demand during periods of system stress.

Accordingly, a severe de-rating of interconnectors is required because:

(1) Their availability is less predictable than for other forms of capacity (being governed by a wider range of factors, including network characteristics); and

(2) The predicted direction of interconnector flows during system stress events is highly unpredictable, with a high potential for exports adding to demand during such events.

The direction of flows depends not only on the likelihood of a system stress event (in both markets) but also on the relative price differential that will apply between I-SEM and BETTA at such times, as well as on a host of operational codes and regulatory interventions. Potential SRMC bidding rules in I-SEM and a lower security standard (8 hours LOLE per annum) than in GB (3 hours LOLE per annum) are also likely to distort interconnector flows in the direction of exports to BETTA.

Interconnectors can therefore guarantee very little by way of energy supply during system stress events, and their capacity must be substantially de-rated for the sake of prudence.

The consequences of overestimating the interconnectors' contribution would be that:

1) Interconnector capacity distorts the cross-border capacity market to the detriment of other capacity providers and to the detriment of security of supply; and
2) Remuneration for over-stated availability would represent a subsidy towards the inefficient construction of interconnection which makes no contribution to system security.

Given the above considerations, it is significant that CRM Consultation 1 (SEM-15-044) suggests a forward looking assessment implies *less* de-rating (i.e. a higher capacity) of interconnectors, compared with historical data. Specifically, paragraph 4.9.17 states the following:

> "…it is possible to infer from EirGrid's Generation Capacity Statement estimate that the capacity contribution of the existing interconnectors

> contribute 617MW of capacity in 2015, but will contribute 777MW in 2020 and 803MW in 2024".

It is plainly incorrect and misleading to conclude that the interconnectors will make an increased contribution towards I-SEM capacity, in the sense of a commitment to supply electricity during system stress events. The RAs also have good reason for doubting the value of this assessment.

CRM Decision 1 (SEM-15-103) indicated (paragraph 4.7.32) that the "RAs will request the TSOs [i.e. EirGrid] to develop the detailed methodology for setting the de-rating factors…and will consult on that methodology". However, Energia believes that EirGrid, as TSO, is not in the position to develop a methodology for setting de-rating factors applicable to the interconnectors in a manner that is objective and impartial having regard to its interest in interconnectors – both in EWIC and in the future Celtic Interconnector (currently undergoing a feasibility study, with a decision planned on whether or not to proceed with the project in mid-2016).

In CRM Decision 1 (SEM-15-103), the regulatory authorities accept that "*depending on the choice of design of the cross-border capacity participation arrangement… there may be a need to address perceived or real conflict of interest" (*para 6.2.5). Mindful that there is a "*need to strike the right balance between maximising synergies and mitigating measures for real and perceived conflicts of interest so that the long term interests of consumers are protected"* (para 6.2.12), the authorities further refer to four main categories of mitigation measures including ring-fencing, behavioral, control/responsibility and transparency. Energia is of the view that the clear and real conflict of interest which would arise for EirGrid if tasked with developing de-rating factors applicable to the interconnectors cannot be addressed by ring-fencing, behavioral or transparency measures because these mitigation measures do not address the source of the conflict of interest, namely EirGrid's interest in the interconnectors. This is the case regardless of the option that is selected by the regulatory authorities in respect of cross-border trading arrangements. The appropriate mitigation measure is in not giving the responsibility of the task of the de-rating of interconnectors to EirGrid and to assign that task to another independent third party under the control of the regulatory authorities.

In this regard, ***given the perceived and real conflict of interest, general principles of administrative law and the principles of constitutional justice, including in particular the principle that the decision-maker may not be biased, the regulatory authorities may not delegate to EirGrid the task of devising a methodology for the de-rating of the interconnectors.*** This means also that the regulatory authorities could not rely on a methodology for de-rating interconnectors developed by EirGrid, however much EirGrid consults the industry upon it.

Energia notes in this respect that any decision made by the regulatory authorities that would be based on a methodology established by EirGrid would be tainted by objective, if not subjective, bias. This is because there will be in all cases a reasonable apprehension that there is a risk that EirGrid in devising the methodology was not fair and impartial. As a result, any decision of the regulatory authorities based on such methodology could not be considered to be objective and non-discriminatory and as such, would be unlawful.

Were EirGrid to develop such a methodology, the regulatory authorities would have no choice but to carry out a fundamental and fully consultative review of EirGrid's work in order to ensure that the decision that they ultimately make is based on sound and objective principles and is not in any way tainted by the conflict of interest that arises for EirGrid. It is not clear how this could be achieved without the regulatory authorities entirely re-doing the work completed by EirGrid. ***A better alternative at this stage accordingly would be to assign this task to an independent third party or to an industry committee working under regulatory auspices.*** Such an open, transparent and independent process would ensure that at no stage during the process was a step made by a party in the position to benefit from the decision, in breach of the elementary conditions for the development of a competitive and level playing field.

3) If there is a preference for the "Interconnector led performance based" approach there will be a need to allocate total interconnector flows between specific interconnectors. Which of the specific approaches set out in 2.4.6 do you prefer? These approaches were:

- ***Balance interconnector utilisation;***
- ***Pro-rata to interconnector metered flow; and***
- ***Complex power flow modelling***

For the Interconnector Led approach to be considered in any way acceptable from both an economic and legal perspective it must be performance based and should furthermore provide a commitment to delivery within the I-SEM. The proposals in the consultation paper do not meet this test (as explained in our general comments to this section and in response to question 1) and therefore the approach for allocating total interconnector flows between specific interconnectors is of second order importance. However, of the methods proposed we would favour pro rata based on metered interconnector flows on the basis that it seems most straightforward to implement.

4) If there is a preference for the "FTR led" approach, which of the specific approaches set out in 2.4.15 (net or gross) do you prefer for the allocation of non-day-ahead flows?

We do not favour the "FTR led" approach for reasons given under general comments above.

5) If there is a preference for the "Performance based Provider Led" approach, which of the specific approaches set out in 2.4.25 do you prefer for the allocation of intra-day and balancing market trades?

- ***As traded***
- ***Pro rata to Reliability Option (in which case – do you prefer "gross" or "net")***
- ***Ignore – all in Balancing Market***

For the Provider led approach to be considered in any way acceptable from both an economic and legal perspective it must be performance based and should furthermore provide an exclusive commitment to delivery within the I-SEM. The proposals in the consultation paper do not meet this test (as explained under general comments above and in response to question 1) and therefore the method of allocating intra-day and balancing market trades is of second order importance. However, of the methods proposed we would favour as traded, if feasible. This aligns treatment of cross border participants with I-SEM participants, avoiding any potential inequality.

6) If there is a preference for the "Hybrid" approach:

- ***Should this be paired with the "Delivery Based" or "Availability Based" provider led approach?***
- ***Should Interconnector participation be mandated or voluntary?***

For the Hybrid approach to be considered in any way acceptable from both an economic and legal perspective it must be performance based and should furthermore provide an exclusive commitment to delivery within the I-SEM. The proposals in the consultation paper do not meet this test. However, with reference to the above question, it is clear that this option would have to be paired with the "Delivery Based" provider led approach. Regarding the mandatory or voluntary participation of interconnectors in the Hybrid system, a more fundamental question about participation that is not asked (and should be) is whether interconnector participation should be mandatory or voluntary for the RO auction. As explained in response to question 1 above, it is our view that interconnector participation (if applicable) should be voluntary for the auction and coupled with the same delivery obligations that apply to I-SEM capacity providers on economic and legal grounds. In the light of this, interconnector participation in the Hybrid system should clearly be voluntary.

2.2 Secondary trading questions

General comments

Delivery of a functional secondary market in ROs is essential to ensure the efficient operation of the I-SEM capacity mechanism.[15] ***Given the significant commercial risks imposed on CRM participants under ROs, which are heightened by the introduction of administered scarcity pricing, it is essential that a functional secondary capacity market is developed to allow participants to either increase their obligations, to reflect availability above their de-rated capacity, or to reduce their obligations, to manage their exposure during planned or forced outages.*** In the absence of a functional secondary market, participants will have to manage these risks by significantly increasing the risk premium in their CRM bids. This is an imperfect hedge, potentially undermining recovery of missing money, and distorting CRM auction outcomes;[16] consequences that will increase costs to consumers.

Energia is particularly concerned about liquidity and market power issues in the secondary RO market. We note that neither of these concerns is acknowledged or discussed in the Consultation Paper, which we view a significant omission. The basis of our concern is:

1. the small size of the I-SEM capacity market;
2. the large proportion of that market likely to already hold ROs; and
3. the dominant position of ESB within the I-SEM capacity market. [17]

The I-SEM Market Power Mitigation (MPM) Consultation Paper (SEM-15-094) presented modelling results that indicate that ESB will be dominant or pivotal in the I-SEM capacity market until 2024 at least, as shown in Figure 1 below.

Figure 1: ESB's Structural Market Power

[15] By 'functional' we mean a liquid market, free from any potential abuse of market power.

[16] For example, because the commercial risk profile of ESB under an RO scheme is significantly less than other I-SEM participants given their large, fuel diverse, generation portfolio. This is explained in more detail later in this section.

[17] The dominance of ESB in the I-SEM capacity market is evident from the modelling work presented in the Market Power consultation paper (SEM-15-094) demonstrating that ESB are likely to have a c50% share of the capacity market by 2024. See figure 1.

Table 6-16: Summary of ESB structural market power metrics in the day-ahead market

Market participant	Capacity market share	Generation market share	RSI < 1.2 (% periods)
2016	44.4%	46.6%	9.1%
2019	46.1%	42.0%	12.5%
2024	52.3%	30.3%	37.5%
2024 (with additional I/C)	52.3%	26.8%	25.1%
2024 (with additional I/C and new gas-fired plants)	49.7%	25.7%	16.9%

Note: Capacity market shares exclude interconnection and wind capacity. Generation market shares include both GB imports and wind generation. The ESB generation market share includes an estimate of ESB wind output.

Source: SEM-15-094, p.62.

Given the small size of the all-island market, the mandatory nature of participation in ROs (for dispatchable generation), and the dominant position of ESB in generation capacity, a generator looking to offset its exposure under an RO contract (e.g. due to planned maintenance or forced outage) will, more often than not, need to trade with ESB. ESB, however, owns and operates the only large, fuel diverse, generation portfolio in the I-SEM, and therefore will not face the same commercial risks as other participants under the CRM, and consequently will not be subject to the same incentives to trade. For example, ESB can offset the exposure of a forced outage on one of its generating units without engaging in any explicit secondary trade of ROs. This is because the energy revenues received on the portion of its generation portfolio not contracted under ROs (e.g. due to de-rating) will provide significant offsetting to exposures to RO difference payments faced by any contracted generation which is unavailable during a scarcity event. This is not the case for other I-SEM participants who have smaller generation portfolio and significantly larger commercial risks. This asymmetry, combined with ESB's status as a state-owned company that may hold non-commercial objectives, undermines its incentives to trade in secondary capacity products, and when considered in conjunction with its dominant position in the I-SEM capacity market, raises wider competition concerns, for example, due to the capability of ESB to potentially physically or financially withhold secondary capacity products from other generation companies and / or trigger scarcity events.

In the light of the above it is essential that the RAs give careful consideration to issues of both market power and liquidity in the design and implementation of the secondary market for capacity, and we recommend that appropriately targeted liquidity promoting measures are implemented in the secondary capacity market (i.e. mandatory contracting obligations on dominant entities, such as ESB), as well as effective market power mitigation measures, to ensure there is adequate access for all CRM participants to competitively priced risk mitigation instruments.

Energia emphasises that failure to implement a functional secondary market in ROs has significant implications for other areas of the CRM design, including stop loss limits and the design of the administered scarcity function. These interactions are discussed in more detail later in this response.

The remainder of this section sets out Energia's answers to the questions in the consultation paper relating to the secondary trading of ROs.

7) Do respondents agree that direct secondary trading of Reliability Options should be permitted?

Yes, secondary trading of ROs is fundamentally important for the reasons set out above and we recommend that careful consideration is given to how any potential barriers to direct secondary trading in ROs can be reduced – e.g. by minimising the administrative burden associated with novation of contractual obligations. Energia therefore support centralised trading arrangements supported by automated systems, with standardised products, credit terms and contractual agreements.

8) Should secondary trading of Reliability Options be via an organised secondary platform? If so, which one of the options is preferred?

We have already established the basis for our concerns about liquidity and market power in the secondary market for ROs. Furthermore, experience of the current SEM forward contract market (ROs are a form of forward energy contract) indicates that liquidity is unlikely to develop organically in the secondary capacity market. Rather, it will require regulatory support and intervention.

With the above in mind, we support the implementation of an exclusive[18], centralised, secondary trading platform (what we believe is the intention behind the Mandatory Centralised Market option presented in the consultation paper). Furthermore, given a liquid secondary market in ROs will improve the overall efficiency of the RO scheme, and promote effective competition, it is essential that such a solution is available for participants from market go-live.

We see the development of a centralised platform as an important first step to reducing potential barriers to secondary trading in ROs. However, this on its own is insufficient. Implementation of explicit liquidity and market power mitigation measures in the secondary market for capacity are also required. Given the secondary capacity market is likely to suffer from similar issues to

[18] "Exclusive" in the sense of the only means to enter into a secondary trade in ROs, an approach that is consistent with the philosophy of the wider I-SEM energy market design.

the forward contract market, Energia recommends that the market power and liquidity issues in the secondary capacity market are included within the scope of the Forwards and Liquidity workstream. In particular, that the Forward and Liquidity workstream explicitly deals with the issue created by ESB's market power in the secondary RO market. It is essential that these issues are properly dealt with to support the efficient operation of the CRM scheme, and wider competition in the wholesale generation market.

9) Do respondents believe that "back-to-back" trading to lay-off exposure to difference payments should be permitted?

Given the likely liquidity issues in the secondary market for ROs Energia would be reluctant at this time to rule out "back-to-back" financial trading. We note that the choice of Option 4b (the Mixed Reference Price) does not eliminate the potential for "back-to back" financial trading, especially for generators on outage, where the default market for RO cash out will be the BM. However, we would emphasise that such trading is extremely unlikely to present a panacea to liquidity and market power concerns (i.e. remove the need for the RAs to implement liquidity and market power mitigation measures in the secondary capacity market), as participants engaging in "back to back" trading in ROs are likely to want to offset their resulting commercial exposures by recourse to operating a physical asset. This is because CRM participants on outage will see most value in trading out their exposures under an RO scheme when the risk of a scarcity event is deemed to be reasonably high. Asset-less traders will only want to trade in ROs when the risk of a scarcity event is deemed to be reasonably low.

The potential issue caused by ESB dominance in the capacity market, which as the modelling in SEM-14-094 demonstrates is most acute when the market is tight, will therefore not be remedied by asset-less traders. Allowing "back-to-back" trading, however, may reduce some of the barriers to trading in ROs for physically backed players, such as a requirement to pre-qualify, or other similar administrative burdens.

We would therefore ask that the trade-off between potential improved liquidity and access to risk management is weighed against any potential risk to system security in relation to allowing "back-to-back" financial trading in ROs, ***but Energia emphasises that this will not address the more fundamental structural issues discussed throughout this section, as "back-to-back" trading in ROs is likely to be physically backed***.

10) With respect to the creation of a centralised Reliability Option secondary market platform:

   a. ***Is there likely to be sufficient demand for secondary trading to justify the cost of the development of a centrally organised platform;***

Given the potential liquidity and market power issues in the secondary market for ROs it is essential that all potential barriers to secondary trade are identified by the RAs and minimised. Energia therefore supports implementation of a centralised secondary market with standardised products (assuming that standard products are made available at low enough granularities to cover participant's trading requirements). If the centralised market was then made the exclusive route to trading in secondary ROs this would pool trade and therefore maximise revenues.

Energia notes that not providing CRM participants with a functional secondary market could increase costs to consumers more than providing any financial support required to a centralised trading solution, due to the premiums added to participant's CRM bids to reflect the commercial risks of not being able to trade out their exposures. Furthermore, we believe potential synergies can be found between developing a centralised platform to support trading in ROs and developing a centralised platform to support trading in forward energy contracts (2 way CfDs), particularly if the platform(s) are made the exclusive means of trading those instruments, an approach that is in keeping with the philosophy of the wider I-SEM energy market design.

b. Do respondents think that capacity providers should be allowed to acquire Reliability Option volume in excess of their de-rated capacity (plus the tolerance margin), and if yes, how the limit on Reliability Option volume for the net primary and secondary volume should be structured?

Yes, given the potential liquidity issues in the secondary market for ROs Energia sees no other alternative than to allow generators to trade in excess of their de-rated capacity. We observe that if such trading is not allowed it is unlikely that there will be a secondary capacity market. We also recommend that generators should be able to trade up to their nameplate capacity, and note that the implementation of Administered Scarcity Pricing in the BM should provide sufficient incentive for generators to trade out their un-contracted capacity prudently – i.e. generators should be allowed to optimise their positions without imposition of lower arbitrary volume caps.

To avoid the risk of physical withholding by dominant generators, we recommend that minimum volume limits should be imposed upon them, and given the portfolio benefits accrued by such participants that the minimum volumes are calculated as the difference between their portfolios nameplate capacity and de-rated RO contract volumes. We note some form of price regulation would also be required for dominant generators to mitigate the risk of financial withholding.

c. What limits should be placed on secondary trading timeframes, including: the timing of secondary trade execution - how soon after the auction should they be allowed, and how late in relation to real time delivery should they be allowed; and the length of the Reliability Option contract which can be traded?

It is essential that there is sufficient liquidity in the secondary market in ROs to allow generators to offset their risk during both forced and scheduled outages. Therefore potential barriers to trading in ROs should be minimised, and secondary trading in ROs restricted as little as possible, while maintaining the overall integrity of the scheme.

Scheduled outages could have a significant lead time while forced outages do not and generators will therefore want to be in a position to trade out of their exposures anything up to 12 months in advance of an outage, or down to as close to real time delivery as within day. Energia therefore request that concerns regarding system security in relation to secondary trading of de-rated capacity volumes are carefully weighed against the risk management requirements of generators, and we note that restrictions on generators ability to trade out their exposures will increase the commercial risk faced by participants, and therefore the cost and efficiency of the RO scheme.

In relation to post event trading, Energia is concerned that allowing this provision could allow large, dominant, portfolio generators, such as ESB, to bypass an exclusive centralised secondary market by transferring their RO obligations between individual units in their portfolio post event. We note the single imbalance price cash out regime means ESB can offset their exposures under ROs across their portfolio even without ex-post trading in ROs, but we nevertheless see no tangible benefit in including this option.

In relation to the length of products we do not believe this should be restricted but we would welcome standardised products subject to the conditions set out in our answer to question 10a above.

d. Should the Capacity Market Delivery Body maintain the processes and capability to undertake pre-qualification throughout the year, and what service standards are required for processing new applications?

Given the potential liquidity issues in the secondary market for ROs we suggest that the Capacity Market Delivery Body does maintain the processes and capability to undertake pre-qualification throughout the year, especially if “back-to-back” trading in ROs is not permitted. This will maximise the volumes available to trade in the secondary market. We note the volume of applications is likely to be reasonably concentrated in the lead up to auctions if such an approach is not adopted, whereas facilitating year round pre-qualification may help reduce this bottle neck. However, we acknowledge that the demand for qualification services is likely to be significantly less outside standard auction timelines and therefore the level of service provision and resourcing should be reflective of this.

e. Should a secondary acquirer of a Reliability Option start from a zero position against each "stop-loss" limit, or should the loss transfer?

The issue of stop-losses only arises under the "direct trades" option, as the original holder retains all RO rights and obligations under the "back-to-back" option (CRM Consultation 2, paragraphs 3.2.3-3.2.5 and Figure 9). The following answer therefore relates to the "direct trades" option.

Energia recommends that secondary acquirers of ROs should start from a zero position, i.e. with the full, unused allowances for losses, for at least three reasons: (1) administrative simplicity (practicality); (2) fulfilling the purpose of the stop-loss (effectiveness); and (3) promoting competition by fostering liquid secondary markets and market power mitigation (transparency, competition).

We note first the additional administrative burden and potential complexity of transferring stop-loss limits. Doing so would incur major costs to track generator performance against individual ROs and to assign penalties against each RO's individual stop-loss. Instead, starting from a zero position would only require the authorities to monitor each market participant's total generation capacity, total portfolio of ROs, and total stop-loss amount.[19]

Second, we believe that the purpose of the stop-loss is to provide individual businesses with some protection against financial risk. To perform this role effectively, stop-losses should be assigned to capacity providers, in proportion to their total holdings of ROs, not to the RO itself. Suppose Generator A sells one RO to Generator B half-way through a year. Generator B should be assigned half a year's stop-loss on that RO to offer the company the appropriate amount of protection against financial risk over the RO's remaining life. How much Generator A called upon the

[19] When a secondary trade takes place, the monitoring system might split the annual stop-loss limit for the RO between the seller of the RO and its buyer, in proportion to the share of the year before and after the trade. However, that adjustment would be necessary in both cases and would refer only to the dates of a trade, not to the performance of all previous holders of the RO

stop-loss during the first half of the year is irrelevant to the protection against financial risk offered to Generator B.[20]

Third, the big advantage of the "zero-position" approach is that it makes all ROs equivalent in the secondary market, so that at any one time there is only one price for secondary trades. Such equivalence hugely improves the transparency and liquidity of any secondary market.

If each RO carried its individual unused stop-loss into the secondary market, each RO would have a different market value, depending on how much of its stop-loss had been used up. Before each secondary trade, market participants would have to exchange information about that RO's unused stop-loss, and to put a bespoke value on it. That would complicate price formation and severely hamper the creation of a secondary market in ROs.

Without the transparency and liquidity provided by a secondary market in ROs, competition would suffer. Smaller generators would be unable to manage their commercial risks. Furthermore, it would be virtually impossible to design the transparent, objective Market Power Mitigation Measures required to ensure that dominant players participate fully in the secondary market for ROs.

Hence, starting from a zero position on stop-losses after each secondary trade is a necessary condition of promoting competition.

Energia therefore recommends that a secondary acquirer of an RO starts from a zero position against each "stop loss" limit.

2.3 Reliability option contract length questions

General comments

Energia fundamentally disagrees with the proposal that only new entrants and re-furbished plants have access to longer term contracts. None of the reasons advanced by the regulatory authorities are in any way sufficient to justify such a fundamental difference in the treatment of capacity providers. In particular no valid or sufficient reason has been provided to justify treating differently the provision of capacity on the basis of whether a plant is existing or not. This difference in treatment favours new capacity but it is not clear why new capacity should be favoured when what is required is that sufficient capacity is available. Favouring new capacity is in this context inconsistent with the promotion of competition. Promoting competition in the supply of

[20] For comparison, consider car insurance, where the "excess" starts afresh with each new owner of a car. A new buyer's excess is not reduced, if the previous owner had made a claim. In the case of the RO, the tradeable property right would be the revenue and the stop-loss, both proportionate to its remaining life; previous use of the stop-loss (i.e. the previous owner's "claims") would not be transferable.

capacity does not require the different treatment of existing and new plants, but addressing the market power that the incumbent operator has on the market in order to ensure that both existing, and to the extent that it is required, new capacity providers compete on the basis of objective, fair and non-discriminatory criteria. Providing an advantage to new entrants is to unfairly discriminate against existing plants and distorts competition in the provision of capacity.[21]

Apart from the obvious and significant legal difficulties of discriminating between (or even defining) new and existing plant, we foresee a number of economic and practical difficulties with offering new entrants very long term contracts. The anomalous approach taken in GB, offering 'up to' 15 year contracts, offers no useful precedent for the I-SEM. Legally it is under challenge[22] and internationally it represents a significant outlier. Other capacity schemes internationally have found it adequate to offer 3-7 year contracts, with the promise of relatively stable (annual) contracts after those contracts end. Indeed other capacity markets have explicitly rejected proposed moves to longer term contracts for new plant alone on the grounds that they are discriminatory towards existing plant and were unnecessary to attract new capacity.[23] Indeed it is telling that some plant in GB opted for contracts much shorter than their 15 year maximum eligibility and we understand there are good reasons for this: (1) longer term contracts are not required and (2) new entrants only select longer term contracts if they believe they will not achieve higher prices in future years. The result is therefore an unhappy equilibrium (for the consumer) whereby long term contracts will only ever have high prices since all the short term contracts will have low prices. Not only will the consumer lock in unnecessarily long contracts at high prices but may also be saddled with stranded costs if demand fails to materialise in future years or if technological progress brings down the cost of capacity.

The incentive problem discussed above arises when the capacity auction (and, as we understand it, the proposed I-SEM capacity auction) applies the same price to new and existing plant, even though new plant has the option of taking a longer term contract than existing plant. We understand that in GB, DECC considered converting the "annual" price emerging from a capacity auction into the equivalent price for a long term contract, using an estimated

[21] Energia notes that the decision of the European Commission of 23 July 2014 approving the State aid to be provided by the UK to capacity providers, including longer contracts for new entrants, has been appealed to the General Court (see Case T-788/14 and also Case 793/14) on the ground, inter alia, that the discriminatory availability of longer contract durations cannot be justified by the legitimate objective of procuring the necessary amount of generation capacity.

[22] Ibid footnote 31.

[23] For instance a move to longer agreements in PJM was rejected by the US regulatory authority (FERC) on the grounds that this was discriminatory against existing plant and that PJM had succeeded to attract investment in new capacity on the basis of single-year agreements. DECC (2013), *Electricity Market Reform – Capacity Market Impact Assessment*, 24 October 2013, page 56.

price duration curve, but all attempts to do so transparently and objectively failed. [24] The prospects therefore for achieving any such conversion in the I-SEM, transparently and objectively, are even less promising, given its smaller size and lower liquidity.

We also foresee practical difficulties with offering new entrants very long term contracts. For example, in each annual auction, long term contracts may only be awarded to a small share of participants. However, these contracts will accumulate over successive auctions and could well end up exceeding the total demand for capacity in future years (i.e. before the first contact had expired). This is a major risk in the small island market given the indivisibility of generation capacity and hence the system's sensitivity to unpredictable demand shocks.

Conclusions

- Energia fundamentally disagrees with the proposal that only new entrants and re-furbished plants have access to longer term RO contracts. None of the reasons advanced by the regulatory authorities are in any way sufficient to justify such a fundamental difference in the treatment of capacity providers. Providing an advantage to new entrants is to unfairly discriminate against existing plants and distorts competition in the provision of capacity.[25]
- Promoting competition in the supply of capacity does not require the different treatment of existing and new plants, but addressing the market power that the incumbent operator has on the market in order to ensure that both existing, and to the extent that it is required, new capacity providers compete on the basis of objective, fair and non-discriminatory criteria.
- Apart from the obvious and significant legal difficulties of discriminating between (or even defining) new and existing plant, we foresee a number of economic and practical difficulties with offering new entrants very long term contracts. The anomalous approach taken in GB, offering 'up to' 15 year contracts, offers no useful precedent for the I-SEM. Legally it is under challenge and internationally it represents a significant outlier.
- Discriminating in favour of new plant may only saddle consumers with higher costs than necessary. Moreover, precedents from other regimes,

[24] DECC (2015), *Capacity Market supplementary design proposals and Transitional Arrangements and Proposed amendments to the Capacity Market Rules 2014 and explanation of some immediate amendments to the Capacity Market Rules 2014*, page 24.

[25] Energia notes that the decision of the European Commission of 23 July 2014 approving the State aid to be provided by the UK to capacity providers, including longer contracts for new entrants, has been appealed to the General Court (see Case T-788/14 and also Case 793/14) on the ground, inter alia, that the discriminatory availability of longer contract durations cannot be justified by the legitimate objective of procuring the necessary amount of generation capacity.

and consideration of the technological and economic risks facing investors, suggest that a shorter contract period is in order. For reasons of administrative simplicity and non-discrimination, we favour a model that offered shorter term contracts to all generators, bolstered by the promise of stable (annual) contracts when those contracts end. Offering all participants (new and existing) the chance to compete for contracts of shorter duration (e.g. 3 to 7 years) will reduce risk and cost to consumers and will avoid discrimination. Should it be shown that conditions in the I-SEM require an even longer duration, we firmly believe, based on our considerable investment experience, that there is no reason to extend ROs beyond 10 years.

- Similar legal, economic and practical issues discussed above apply equally in respect of DS3 system services contracts.

11)Principle of Longer Term Reliability Options:

a. Do respondents agree that plant requiring significant investment should be able to avail of longer term Reliability Options?

It would appear to be SEM Committee's intention that existing plants can only access longer term contracts when material new investment is required. Energia fundamentally disagrees with this position as explained in our general comments to this section as this constitutes unfair discrimination against existing capacity providers and is inconsistent with the principle of equal treatment. We also foresee practical and economic problems with offering new entrants (or re-furbished plant) longer contracts than existing plants as explained in our general comments above.

b. Do respondents agree that existing plant should be restricted to reliability options with a term of 1 year?

No. Not if other capacity providers (either new entrants or plant requiring significant investment) have the option of bidding for longer term contracts. To do so would constitute unfair discrimination against existing capacity providers and would be inconsistent with the principle of equal treatment. It also presents significant practical and economic problems as explained extensively in our general comments to this section.

c. Do respondents believe that longer term Reliability Options should only be available to new-build plant, or should also be available to existing plant where significant investment is being made to enhance or maintain its capability to provide capacity?

Apart from the obvious and significant legal difficulties of discriminating between (or even defining) new, existing and upgraded plant, we foresee a number of economic and practical difficulties with offering only new entrants and upgraded plant very long term contracts.

If longer term Reliability Options are made available they should be made available to all capacity providers (whether existing, refurbished or new) for reasons explained extensively in our general comments to this section.

12)Classification of plant as new, upgrade or existing

a. Do respondents have a view on which approach should be used to classify capacity providers as "new", "upgrade" or "existing"?

Given our response to question 11a), b) and c) above, this classification should only be applied for the purpose of pre-qualification, implementation agreements and performance bonds and not for determining eligibility to bid for longer term contracts. It should be based on transparent and objective criteria that are pre-determined based on experience, evidence and expert judgement.

b. Do respondents prefer the approach of classifying providers as "new", "upgrade" or "existing", please indicate your view of the criteria, evidence and thresholds that should be used to inform this classification.

As discussed above in response to question 11a), b) and c), this classification should only be applied for the purpose of pre-qualification, Implementation Agreements and performance bonds and not for determining eligibility to bid for longer term contracts.

The criteria, evidence and thresholds to apply are finer details best progressed through an industry Working Group under the auspices of the RAs.

There also needs to be formal disputes resolution process through which the party concerned and third parties can object and raise a dispute.

13)Maximum available Reliability Option lengths

a. ***Do respondents have a view on the appropriate maximum Reliability Option lengths that should be available to new-build and upgraded plant?***

Apart from the obvious and significant legal difficulties of discriminating between (or even defining) new, existing and upgraded plant, we foresee a number of economic and practical difficulties with offering only new entrants and upgraded plant very long term contracts. See detailed discussion of these points in our general comments to this section.

The somewhat anomalous approach taken in GB, offering "up to" 15 years, therefore offers no useful precedent for the I-SEM. Legally it is under challenge[26] and internationally it represents a significant outlier.

[26] Ibid footnote 31.

Examples of the 3-7 year contracts in other markets provide the best indication of what is required. However should it be shown that conditions in the I-SEM require an even longer duration, we believe that there is no reason to extend ROs beyond 10 years.

b. How do respondents view the Reliability Option lengths in relation to the five generic frameworks set out in this section.

See response to question 13a above. The somewhat anomalous approach taken in GB, offering "up to" 15 years offers no useful precedent for the I-SEM. Legally it is under challenge[27] and internationally it represents a significant outlier. We believe that there is no reason to extend ROs beyond 10 years which fits into the 'Balanced Economic Life' category.

2.4 Stop-loss limits questions

General comments

It is essential that the design of the RO scheme ensures that CRM participants are provided with the appropriate risk mitigation measures to manage their exposure to RO cash out payments.[28] This includes a functional[29] secondary capacity market, with effective market power mitigation measures, and appropriately set stop loss limits.

It is also imperative that the design of the RO scheme does not unduly penalised CRM participants for non-delivery that is outside of their control (e.g. a result of dispatch / scheduling risk), as this would result in the imposition of unwarranted and unmanageable commercial risk. Energia observe that excessive and uncapped commercial risk will distort CRM outcomes, due to the lower risk profile of ESB under an RO scheme,[30] and make it substantially more difficult to finance investment, therefore presenting significant barriers to new entry.

Therefore, in the design of the I-SEM CRM, it is essential that an appropriate balance is struck between the desire for strong incentives under the RO scheme, the imposition of commercial risk, the overall level of that commercial risk, and the risk management instruments available to participants to manage their financial exposures. ***Failure to appropriately balance these aspects of the CRM design could result in market failure.***

[27] Ibid footnote 31.
[28] The required risk mitigation measures are discussed in more detail in the section of this response dealing with the detailed design of Administered Scarcity Pricing.
[29] By 'functional' we mean a liquid market, free from any potential abuse of market power.
[30] The reason why this is the case was explained in detail in the section of this response dealing with the secondary capacity market.

Energia therefore welcomes the decision to implement stop loss limits, which will provide a cap on the maximum level of financial exposure a participant would be exposed to under the CRM. We believe the introduction of stop loss limits, if combined with a functional secondary market in ROs, may provide potential mechanisms that, if properly implemented, could help participants manage their financial exposures and cash flow liabilities under an RO scheme. Energia nevertheless observes that market power issues in the secondary capacity market, combined with the significant advantage conferred upon ESB under an RO scheme,[31] mean that other generation companies will face disproportionate, and higher, commercial risks when participating in the CRM. These risks are further escalated by the introduction of administered scarcity pricing. ***This is an extremely serious issue for competition in the wholesale generation market and requires very careful consideration.***

Energia therefore recommends the following high-level characteristics are implemented in the design of stop loss limits. These will help to provide an appropriate cap on the financial exposures faced by participants, and offer some, albeit, limited protection, against potential exertions of market power. ***Energia emphasises however that they in no way undermine the need for the delivery of a functional secondary capacity market, or the other risk mitigation measures highlighted in this response.***

1) That annual limits are set such that the potential loss under an RO contract cannot be more than the revenue received – so if based upon a multiple of capacity receipts, this multiple is set at a maximum of 1. This will retain appropriately robust incentives under the RO scheme, while providing participants with at least some protection from excessive commercial risk, and exertion of market power. Energia note that at a VOLL Price of €10k, a single hour of forced outage during a scarcity event will cost a 400MW CCGT €4m; a figure that has significant implications for cash flow and bottom line profitability.

2) We observe that the implementation of administered scarcity pricing significantly increases the requirement for a monthly stop loss limit. We therefore recommend that such limits are introduced, and their levels set appropriately to allow participants to manage their cash flow risk.

[31] ESB owns and operates the only large, fuel diverse, generation portfolio in the I-SEM, and therefore can offset the exposure of a forced outage on one of its generating units without engaging in any explicit secondary trade of ROs. This is because the energy revenues received on the portion of its generation portfolio not contracted under ROs (e.g. due to de-rating) will provide significant offsetting to exposures to RO difference payments faced by any contracted generation which is unavailable during a scarcity event. This is not the case for other I-SEM participants who have smaller generation portfolios and significantly larger commercial risks.

3) That daily limits will be required if monthly limits are set too high.

Energia further recommends that the detailed design of stop loss limits are consulted upon as part of the development of the CRM market rules, when the detailed design of the RO scheme will be more advanced, making it easier for participants to more accurately estimate their commercial risks.

14) Do respondents favour the I-SEM Capacity Year running from October to September, with annual stop loss limits applying over that I-SEM Capacity Year?

It is imperative that annual stop loss limits are aligned with the I-SEM capacity year. However, Energia does not agree that it is necessary for the definition of the capacity year to be changed to accommodate this objective. We note that regardless of the start date of the I-SEM capacity year, six winter months will be included within the definition. Therefore, subject to the current SEM capacity scheme operating until 31st December 2017, Energia recommends maintaining the current SEM definition of 'capacity year'. Furthermore, if it is deemed significantly important to include six contiguous winter months within the definition then, subject to the current SEM capacity scheme running until 30th March 2018, Energia suggests that the I-SEM capacity year is defined as the period from 1st April Y to 30th March Y + 1. Energia notes that this approach has the benefit of maintaining additional flexibility around the I-SEM go live date following the first T-1, or the initial combinatorial auction.

15) Do respondents believe that "per event/day" and "per month" limits are required in addition to the annual stop loss limit?

The introduction of administered scarcity pricing could lead to widespread insolvency issues and create barriers to securing financing for new investments if monthly stop loss limits are not introduced to manage cash flow risk for CRM participants. Energia note that at a VOLL Price of €10k, a single hour of forced outage during a scarcity event would cost a 400MW CCGT €4m; a figure that has significant implications for cash flow and bottom line profitability. We therefore support the introduction of monthly stop loss limits, and can see potential advantages in daily / per event stop loss limits, subject to the final level set for any monthly limits. Furthermore, we recommend that the detailed design of stop loss limits is further consulted upon as part of the development of the detailed CRM market rules as set out in our general comments on this section above.

16) Which approach do respondents favour for the definition of the Per Day/event limit?

Given the potential issues highlighted in the consultation paper with defining events we believe any limits introduced at a granularity of less than one month should be on a per day basis.

17)Please provide views on the appropriate levels for the each of the proposed stop loss limits.

As discussed above, Energia recommend that the detailed design of stop loss limits and their final values should be determined as part of the development of the CRM market rules, when more information will be available on the detailed design of the RO scheme, and participants will be able to more accurately estimate their commercial risks and potential financial exposures. Our current views on stop loss limits however are provided below. The rationale behind these recommendations is set out in the general comments to this section.

- **Annual Limits:** That annual limits are set such that the potential loss under an RO contract cannot be more tb8han the revenue received – so if based upon a multiple of capacity receipts, this multiple is set at a maximum of 1. This will retain appropriately robust incentives under the RO scheme, while providing participants with at least some protection from excessive commercial risk, and the exertion of market power. Energia notes that at a VOLL Price of €10k, a single hour of forced outage during a scarcity event will cost a 400MW CCGT €4m; a figure that has significant implications for cash flow and bottom line profitability.

- **Monthly Limits:** We observe that the implementation of administered scarcity pricing increases the requirement for monthly stop loss limits to allow participants to manage their cash flow risk. Implementation of appropriate monthly limits is therefore required to avoid widespread insolvency issues and reduce barriers to securing finance for new investment.
- **Per event / Daily Limits:** We note that the requirement for per event / daily limits depends upon the level of the annual stop loss limit and the existence, and levels, of any monthly stop loss limits. Energia concludes that daily limits may be required depending upon the design of annual and monthly stop loss limits, particularly if monthly stop loss limits were not introduced, or were set at a level that is too high to avoid widespread insolvency issues or potential barriers to financing and therefore new entry.

2.5 Commissioning window and implementation agreements questions

General comments

Robust measures should be put in place to prevent 'ghost capacity' from entering the auction given the implications for security of supply and the criticality of capacity revenues for generators. It is also essential to the extent that providers do not deliver upon their contractual commitments that the capacity requirement in the T-1 auction is adjusted accordingly. This is not considered in the consultation paper.

A number of questions in this section of the Consultation Paper cannot be fully or definitively answered at this stage and are best addressed through an industry Working Group convened by the RAs to cover the finer details of pre-qualification requirements, implementation agreements, and performance bonds. Given the complexity associated with taking investment decisions, we would strongly encourage the formation of such a Group to help ensure proper consideration of all of the issues, given the importance of generating the market conditions required to deliver new investment into the I-SEM.

18)Is a period of four years from the Auction Date to the start of the first Delivery Year appropriate?

Depending on the prequalification requirements for the auction four years should be sufficient time between the Auction Date and the start of delivery under the reliability option. Energia considers that the prequalification requirement should include material consents such as Planning Permissions otherwise the four year period would be insufficient. However projects without planning permission, if required, would present significant risk of non-delivery. The connection application processes will need to be considered in relation to the proposed process for new capacity providers and the allocation of reliability options. It may be appropriate to have a grid connection offer prior to participation in the auction as well as options to lease land, if appropriate.

19)Does setting the Long Stop Date at 18 months after the start of the first Delivery Year strike the correct balance between the costs incurred by the market and the ability for delayed or longer-running capacity projects to be completed?

The 18 month long stop date is appropriate. It is important to include protections for delays which are outside the control of the Capacity provider and within the control of network operators, network owners and statutory bodies. For example delays due to Grid or Radar. Grid delays must not impact on the length of the contract and the Capacity Provider must be entitled to Option Fees for the maximum term of the contract.

20)Are the proposed milestones reasonable?

We would expect that Planning Permission for the project would be granted prior to a potential Capacity Providers competing in an auction rather than something which may be outstanding at the Substantial Financial Commitment Stage. Certain planning compliance conditions may still need to be satisfied before Commencement of Construction.

We would agree with the need to have a Commencement of Construction milestone. Given the diversity of potential Capacity Providers the definition of this milestone is likely to be difficult to define for all potential providers.

However definitions could be developed for many of the existing technologies based on typical milestones in EPC contracts.

We would agree with the Substantial Completion milestone.

We would agree that inclusion of the additional milestones set out in the consultation would be appropriate.

Some of the proposed milestones may need to be reviewed to reflect new technologies.

21)Are there any other milestones, especially prior to Substantial Financial Commitment, which could be used to add security to the delivery of new capacity?

This is a detailed point that is best addressed through an industry Working Group convened by the RAs to cover the finer details of pre-qualification requirements, implementation agreements, and performance bonds.

22)What proportion of the contracted capacity is appropriate to use to identify Substantial Completion?

We would support implementation of a similar definition of Substantial Completion which is used in GB which includes producing 90% of the reliability Option capacity, after de-rating.

23)Is six-monthly reporting appropriate?

We would support independent verified reporting against four key milestones every six months. We would also support more frequent reporting (without independent verification). If this reporting was limited to reporting progress against the Project Schedule, or an abridged version of the Project Schedule, we do not see why monthly reporting should be an issue and would reflect good project management.

24)Do any (or all) of the reports need to be independently verified?

We would recommend that the six monthly report should be independently verified. However, irrespective of these reports being independently verified, there is a potential conflict of interest between EirGrid's role as TSO and its interest in future interconnection which is relevant in this context if interconnectors participate in the capacity scheme.

25)Does 18 months provide sufficient time after the Auction Date to achieve Substantial Financial Commitment?

For major generation projects it would be appropriate to have 18 months as the maximum period between the Auction Date and Substantial Financial Commitment milestone.

26)Is it appropriate to terminate a Reliability Option for failure to achieve Substantial Financial Commitment?

Yes. Energia believes that it is appropriate to terminate the Reliability Option if a Capacity Provider does not achieve Substantial Financial Commitment within a suitable window. This window should reflect a proportion of the 18 month period which is allocated to the long stop date window. Consideration should be given to remedy periods, for issues which may technically result in failure to achieve Substantial Financial Commitment, in strict accordance with the definition, however the technical breach will not result in the ability of the project to reach Substantial Completion in accordance with the timelines of the Project Schedule.

27)Should failure to achieve any other milestones (within a suitable window) trigger termination of the Reliability Option?

Energia believes that with sufficient flexibility in the definition and with a suitable window for remedy, there could be a financial incentive, such as a call on a proportion of the performance bond, to achieve first export of energy to the network. For large scale power projects reaching Substantial Financial Commitment represents a very significant commitment to the project. It is in the interests of customers and the capacity provider that the project is delivered and the Implementation Agreement should reflect this for large infrastructure projects. A termination of a Reliability Option after the Substantial Financial Commitment milestone will have potential implications for financing projects on the island of Ireland as equity and debt providers will have realised significant losses. This unintended consequence of the termination of a reliability option after the Substantial Financial Commitment milestone could increase the perception of risk of investing in the I-SEM and the cost of financing new capacity could be adversely impacted.

28)Is it appropriate to partially terminate a Reliability Option if it can achieve 'Minimum Completion? What level should be set for Minimum Completion?

Whilst there may be a superficial appeal that partial termination would be preferable to full termination, for financing a project it would be completely unworkable. A project should be given every opportunity to meet the criteria by its longstop date. If the longstop date is not met, then it should fail completely.

If a project delivers partial capacity by the longstop date, then we agree with the approach to sacrifice the bond pro rata. However there should not be an extension to the longstop date unless force majeure is applicable. A longstop date should be a longstop date.

29)If a Reliability Option is terminated under the terms of the Implementation Agreement, should this project be 'sterilised' for a period of time following the termination and be unable to participate in capacity auctions?

We suggest the answer to this depends on the reason for termination. If the reason for termination is that the RO price obtained is too low so that the project is uneconomic, then the project should be sterilised, as in GB CfD auctions. There has to be a consequence for underbidding. If the reason for termination is a project issue that can ultimately be fixed, then the project should not be sterilised, but should have the opportunity to bid again.

30)Should the I-SEM consider terminating Reliability Options if the information submitted as part of the qualification process is discovered to be false or mis-leading?

The pre-qualification criteria should be rigorous, and there should be diligence as part of the auction process to minimise the risk of false or misleading information being relied upon. The wording proposed in this question is too vague. Disqualification should only occur if *relevant* information is found to be *deliberately falsified* or *deliberately misleading*.

31)Do respondents agree that the level of the performance bond should be based on a pre-estimate of the cost to the market of non-delivery of contracted capacity?

Some linkage to the RO price has to be right if this is to be a pre-estimate of the cost to the market of non-delivery. The question is what percentage to apply. We suggest that an appropriate level could be in the range of 10%-20% of total RO revenues (so for a 10 year contract this would be equivalent to 1-2 years of RO revenues). However the level of performance bond should not be decided through this consultation process. This is detailed point that is best addressed through an industry Working Group convened by the RAs to cover the finer details of pre-qualification requirements, Implementation Agreements, and performance bonds.

32)Do respondents agree with the principle that the level of performance bond should rise over time, reflecting increased costs to the market? If not, what alternative principle should be used and why?

No, to apply this principle would be far too complicated and would not work for financing. The performance bond should be fixed as suggested in response to question 31) above, and called pro rata to the extent that capacity is not available to participate. It is not possible to provide a fully thought through alternative principle in the context of this consultation. This is detailed point that is best addressed through an industry Working Group convened by the RAs to cover the finer details of pre-qualification requirements, Implementation Agreements, and performance bonds.

33)At what level in €/MW does the performance bond create a serious barrier to entry? Does this differ for small vs large plant or for different technologies?

Energia believes that I-SEM should uniformly cap the level of the Performance Bond to €5k/MW.

The SEM Committee should consider netting arrangements in order to optimise the cost of providing credit in the I-SEM.

34)Do respondents agree with the principle that use of a fixed €/MW level for all participants, regardless of size, to set the size of the performance bond does not fully capture the costs and risks to the I-SEM and that a more complex approach is needed? Do participants have an alternative preferred method for handling the greater risks to the I-SEM created by larger new capacity projects?

The €/MW approach allows for difference in scale and keeps the rules simple.

35)How should the level of the performance bond change over time? Should this have any link to the milestones?

Performance bond should be simply based on delivery of capacity before the longstop date. To the extent that capacity delivered is less than contracted, bond should be reduced pro rata. Otherwise if no capacity is delivered, bond should be forfeited in full.

36)Do you consider that the Time To First Delivery (/Time to LSD) proposed here for the CRM should also apply equally to the delivery of System Services under the DS3 arrangements? If you consider that the time (s) should be different, on what basis / what rationale should they differ?

From a delivery timing perspective, there is merit in aligning DS3 with CRM. However due to the necessity of contracting system services as soon as possible due to the increasing level of system non synchronous penetration and the removal of payments for curtailment from 2018 and constraint payments if a market participant does not have a Day-Ahead position in I-SEM System Service initially the Contract Start Date for System Services should be earlier if a provider can deliver the services more expediently than four years.

2.6 Administered scarcity pricing questions

General comments

The decision to rely exclusively on the performance incentives inherent in the RO contract necessitates that other relevant energy market parameters, such as the level of the Full Administered Scarcity Price (FASP), and the administered scarcity price function, are appropriately designed to deliver the required incentives to ensure the efficient operation of the CRM. Energia however also notes the need to balance the need for appropriate incentives with the requirement for participant’s to be able to adequately manage their commercial risks, both in relation to imbalance exposure and exposures under the RO scheme, including cash flow.

To avoid market failure, introduction of an administered scarcity price tending towards VOLL (i.e. at GB VOLL) is therefore only feasible ***if the following requirements relating to risk management are met:***

1) A liquid, transparent, exclusive and fully functional IDM to allow participants to appropriately manage exposure to energy imbalances;
2) A liquid, transparent, exclusive, centralised secondary market for ROs, with appropriate and effective market power mitigation measures, including volume obligations on dominant participants, to allow generators to manage their financial exposures associated with planned and forced outages;
3) A liquid, transparent, exclusive, centralised forward contract market with appropriate and effective market power mitigation measures, including volume obligations on dominant participants, to allow suppliers and generators to hedge their residual exposures up to the RO strike price;
4) Exemptions from RO cash outs for generators that are available but not dispatched at times of scarcity;
5) Appropriate stop loss limits to protect existing participants from bankruptcy and to remove potential barriers to financing for new investment.

If these requirements are not met by I-SEM go live then introduction of an administered scarcity price that tends towards VOLL (even if set at GB levels) imposes large and unmanageable commercial risks on participants, and potential market failures. Energia observe, therefore, that there is a strong incentive to deliver upon these requirements given a decision not to implement administered scarcity pricing, at a level at least equivalent to GB VOLL, in the longer term could have implications for:

1) I-SEM security of supply, as the I-SEM could be exporting to GB at times of co-incidental scarcity;
2) the wider feasibility of the CRM design, as penalties for non-delivery under the RO scheme would be weakened; and
3) the proper functioning of the wider I-SEM energy market arrangements, including potential revenue adequacy issues, given the prescriptive SRMC market power mitigation proposals being considered for the balancing market.

On balance, however, and given our significant concerns regarding the delivery of appropriate risk mitigation instruments, including a functional secondary market, for participants across energy and capacity markets, Energia believe that transitioning from the EUPHEMIA price cap up to a maximum Full Administered Scarcity price, while a compromise, would seem sensible. The timing of this transition should be made contingent upon the successful delivery of the risk mitigation and market power mitigation measures outlined above, and the restrictions set out in our answer to question 44 and the paragraph below.

In relation to the administered scarcity pricing function Energia would emphasise that there is a balance to be struck between modelling accuracy and spurious complexity, which could lead to increased commercial risk for CRM participants without significantly improving system security. Therefore Energia recommends a static administered scarcity function that is stable and predictable. Furthermore, we suggest that the value of X, at least for a transitional period, should be set such as FASP * X equals the RO strike price. Furthermore, to limit undue regulatory risk, we recommend that changes to the administered scarcity price function that increase the rate at which administered pricing tends towards the FASP are only made with a lead time that is greater than the lead time for the T-4 auction. Otherwise this results in under-recovery by participants under the CRM, due to RO cash out at times of scarcity being higher than levels anticipated by CRM participants when bidding in the CRM auction.

37)Which of the options do respondents prefer (and why) for the enduring level of the Full Administered Scarcity Price (FASP)?

- ***a. VoLL;***
- ***b. EU Consistent (e.g. with GB);***
- ***c. Euphemia Cap; or***
- **d.** ***Existing SEM PCAP***

The enduring value of the FASP should be set at a level that is sufficient to promote system security within I-SEM and the wider context of interconnected European markets. Given interconnection with GB, and the future implementation of the EU code on Network Balancing, Energia therefore recommend I-SEM VOLL is aligned to GB VOLL on an enduring basis. We believe this will provide the appropriate market signals under the energy trading arrangements and CRM over the long term without distortion of cross border trade. As set out above, however, we believe there are strong grounds to consider transitioning to this level from a lower scarcity price, ***and recommend that this must be the case if the following requirements relating to risk management are not met:***

1) A liquid, transparent, exclusive and fully functional IDM to allow participants to appropriately manage exposure to energy imbalances;
2) A liquid, transparent, exclusive, centralised secondary market for ROs, with appropriate and effective market power mitigation measures,

including volume obligations on dominant participants, to allow generators to manage their financial exposures associated with planned and forced outages;

3) A liquid, transparent, exclusive, centralised forward contract market with appropriate and effective market power mitigation measures, including volume obligations on dominant participants, to allow suppliers and generators to hedge their residual exposures up to the RO strike price;
4) Exemptions from RO cash outs for generators that are available but not dispatched at times of scarcity;
5) Appropriate stop loss limits to protect existing participants from bankruptcy and to remove potential barriers to financing for new investment.

In relation to the level of any lower transitional level for FASP we observe that setting a price cap in the balancing market that is below the price cap in the DAM (i.e. using the current SEM price cap) would dampen ex-ante energy market prices in I-SEM relative to other European markets (particularly GB). This in turn would result in distortion of cross border trade during periods of system stress in either market. We note that this distortion would be less pronounced if the EUPHEMIA price cap were used.

Energia therefore supports the use of the EUPHEMIA price cap as the starting level of FASP and recommends that the FASP transitions to a maximum of the GB VOLL price subject to the risk management requirements outlined above being met.

38)Do respondents agree with the definition of full load shedding (when Full ASP applies) as set out? If not please explain why, and your proposed alternative definition.

The definition of full load shedding provided in the consultation, which is based upon the criteria set for EirGrid red alerts, seems to contradict the statement in paragraph 5.3.10 on page 95 of the consultation paper "that Administered Scarcity Pricing will not apply at times when there is sufficient available capacity, but it cannot start / ramp up fast enough leading to a short term reduction in operating reserve". Paragraph 5.3.10 seems to imply a definition of system scarcity based on the available installed MWs of capacity (an installed capacity approach), rather than the MWs of capacity that can be physically dispatched (a dispatchable capacity approach). The installed capacity approach would seem incompatible with a definition of scarcity based upon the current criteria for EirGrid red alerts.

Energia notes that adopting an installed capacity approach would be easier to forecast and therefore would reduce commercial risks on participants, but may result in times when there is a real time load shedding event, but administered scarcity pricing is not in effect. On the other hand, adopting a dispatchable MW approach would mean that administered scarcity is always in effect when there is physical load shedding, possibly bypassing the administered scarcity price function,[32] but makes the ability of CRM participants to forecast the frequency of administered scarcity pricing more complex, as scarcity could be triggered by TSO dispatch decisions and / or transmission system constraint management, rather than overall system margin. This would significantly increase participant's commercial risks under the CRM. We believe this issue cuts across a more fundamental question in relation to the I-SEM design philosophy, namely, whether the I-SEM energy markets are unconstrained; or whether pricing should be affected by TSO dispatch decisions (including constraining for reserves) and system constraint management?[33]

Energia observes that the distinction between these two approaches is fundamental, both in terms of assessing how ASP will work, and for participants to be able to determine the commercial risks they are likely to be subject to under the RO scheme. On balance Energia recommends a definition of scarcity based upon the installed capacity approach, not defined in relation to EirGrid red alerts. This will reduce dispatch and scheduling risk imposed upon CRM participants and will allow them to better estimate and manage their commercial risks under the RO scheme.

However, irrespective of which definition of scarcity applies, it is imperative that generators are not held liable for RO difference payments when they are available, but not scheduled / dispatched by the TSO during an administered scarcity event.[34] This will avoid the imposition of unmanageable commercial risks on CRM participants (e.g. resulting from TSO dispatch and system management decisions outside of their control).

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[32] In the sense of balancing market pricing escalating straight to the Full Administered Scarcity Price.

[33] Energia's understanding from the HLD decision was that energy markets would be unconstrained but we note DS3 proposals regarding plant repositioning for reserves and other system services via ex-ante markets (resulting in constrained ex-ante markets), the decision not to allow generators constrained off for network reasons to access infra-marginal rent in the balancing market (a change to the firm access policy), and the current proposed approach to imbalance pricing that results in significant pollution of the imbalance price by TSO system actions.

[34] CRM Decision 1 (SEM-15-103) states that "Generators can manage [scheduling] risk by trading in the IDM to ensure they are dispatched against a deliverable profile and are in position to deliver their RO commitment" (paragraph 4.3.20). A similar statement was made by the RAs' representatives at the CRM2 workshop in Dundalk on 20 January 2016. It is important to recognise that the IDM in I-SEM will be opened in parallel with the BM (which is unusual) and when combined with market power issues (given the large retail and generation market share of ESB) could well result in liquidity issues in this market. Irrespective of liquidity problems in the IDM, we cannot stress enough that if notice of a potential scarcity event is provided to the market after a generator's notice time then that generator will not be able to trade into a dispatch position in time for the scarcity event via the IDM. It is therefore fundamentally important to ensure that generators are not held liable for RO difference payments when they are available, but not scheduled / dispatched by the TSO during an administered scarcity event.

39)Do respondents agree that virtual bidding removes any incentives on capacity providers to withhold power from the DAM or the IDM to sell in the BM? Do you agree that this applies regardless of what market power controls are placed on DAM, IDM and BM bids? Do you agree that this applies regardless of the level of the Full ASP? If you do not agree, please explain why.

As we understand the mechanism of virtual bidding, a generator that submits a virtual bid will clear their own offers, thereby creating a "pseudo" trade with a net volume of zero in the DAM or IDM, which could potentially prevent other bid side participants from purchasing requirements in ex-ante timeframes – e.g. if the generator bids at the price cap. We may have misunderstood the concept but this would seem to be a form of withholding from earlier market timeframes, and given the market power issues inherent with the I-SEM energy and capacity markets (please cross reference the RA modelling results presented in SEM-15-094) we question whether the introduction of such a mechanism is a good idea. We certainly believe it needs further careful consideration.

Furthermore, under the I-SEM energy trading arrangements, acceptance of a generator virtual bid could result in reduction of the generator PN by the volume of the bid, unless specific market rules are introduced to prevent this,[35] thereby resulting in physical withholding of generation as well. This could cause unusual trading incentives, given the parallel opening of the IDM and BM, combined with the implementation of substitutive PNs.

While we can see how virtual bidding is a useful tool to signal expectations of scarcity in ex-ante timeframes in large, competitive markets (i.e. how it could produce timely market signals), we are concerned that within the specific context of the I-SEM, which is a small, highly concentrated market, the mechanism could leave the demand side of the market short, and exposed to high imbalance prices up to the level of the RO strike price at times of scarcity. Furthermore, if clearing of virtual bids reduces generator PNs then it could also create potential system management problems for the TSO under the current I-SEM energy trading arrangements.

Energia therefore requests that the concept of virtual bidding is clearly defined and explained within the context of the I-SEM energy trading arrangements. Without such clarification it is difficult for participants to provide definitive

[35] In the instance where acceptance of the virtual bid does not reduce the generator PN (i.e. it confers the right of dispatch onto the generator), and assuming that the generator was cashed out at the imbalance price, which is the point of virtual bidding, the generator would effectively be signalling to the TSO that they wished to spill into the balancing market. This would seem like a form of self-scheduling. Energia are not against self-scheduling but are confused as to why it would be allowed in this particular specific instance and not more generally under the market design. We note that self-scheduling would help address the risk management and market power issues Energia has highlighted since the HLD debate and that are discussed in this response within the context of the CRM.

views on the mechanism. Once this clarification is provided the mechanism should be further consulted upon before any decisions are made regarding its appropriateness, or potential impact on market incentives.

In relation to the incentives on generators to withhold from the DAM under an RO mechanism, this would seem to be a function of the market price cap and RO strike price, which acts as a revenue caps on generators that hold a capacity contract. If different price caps are set for different markets, and, in particular, if the price caps in later markets, such as the BM, are higher than earlier markets, then this, combined with the increased risk of scarcity being accurately anticipated and therefore priced into markets closer to real time, would create the incentive to withhold until later timeframes. While not removed, this incentive is muted if the strike price of ROs is set at the same value across all timeframes. We note that setting different market price caps in different market timeframes will incentivise un-contracted generators to sell power (or for RO contracted generators, to sell that portion of their output not contracted under the CRM scheme) in the timeframe where they expect to receive highest remuneration during scarcity events.

Energia therefore observes that transitioning from a scarcity price based upon the EUPHEMIA price cap to a scarcity price equal to GB VOLL would allow for further consideration of any potential adverse impacts on energy market dynamics of implementing a price cap in the BM that is higher than the DAM.

40) If stakeholders consider that it is appropriate to set the Full ASP at a lower level for an introductory period they should also set out, how long that introductory period should be and why, or alternatively the principles that the SEM Committee should employ in deciding when to move from the introductory full ASP to the higher rate full ASP.

See the introduction to this section and our response to question 37 above where we recommend and set out the rationale for transitioning from the EUPHEMIA price cap to a scarcity price equivalent to GB VOLL. As set out in that answer we believe no firm time period should be set for this transition, although any changes to the administered scarcity pricing function should be subject to the restrictions set out in our answer to question 44 below, but rather that the decision to move to the final FASP should be conditional upon ***the following requirements relating to provision of appropriate risk management instruments being met:***

a. A liquid, transparent, exclusive and fully functional IDM to allow participants to appropriately manage exposure to energy imbalances;

b. A liquid, transparent, exclusive, centralised secondary market for ROs, with appropriate and effective market power mitigation measures, including volume obligations on dominant participants, to allow generators to manage their financial exposures associated with planned and forced outages;

c. A liquid, transparent, exclusive, centralised forward contract market with appropriate and effective market power mitigation measures, including volume obligations on dominant participants, to allow suppliers and generators to hedge their residual exposures up to the RO strike price;

d. Exemptions from RO cash outs for generators that are available but not dispatched at times of scarcity;

e. Appropriate stop loss limits to protect existing participants from bankruptcy and to remove potential barriers to financing for new investment.

41)If you favour a different level of Full ASP, either for an introductory period, or after any introductory period, please indicate the level and justify your response.

No, please see response to questions 37, 38 and 40 for our reasoned rationale behind supporting a transition from a scarcity price set at the EUPHEMIA price cap to an enduring final FASP equal to GB VOLL.

42)Do respondents agree with the proposed approach of using a static approach to setting the piece-wise linear ASP function at the inception of the I-SEM, and if not why not? If yes, do you agree with the proposed approach of setting the piece wise linear equation as a function of the remaining MW of available operating reserve?

Energia agrees with the proposed static approach as it reduces the complexity associated with forecasting administered scarcity pricing levels, and therefore allows for more efficient pricing of the RO by participants. Furthermore, we recommend that this is the approach that should be implemented on an enduring basis. We do not believe that a dynamic LOLP value should be introduced unless it can be clearly demonstrated that the additional complexity, and forecasting risk it creates for participants, will significantly improve market signals, and therefore system security, compared to using a static curve (i.e. that the system benefits clearly outweigh the increased financial risk for participants).

Energia agrees that the balancing market price determined by the scarcity pricing function should increase as the remaining MWs of target operating reserves reduce. For our views on how this relationship should be defined please see our answer to the next question.

43)What should the value of X in Figure 12 be?

To provide stability, we recommend that the value of X should be static and initially set such that X * FASP is equal to the strike price of the RO.

Furthermore we suggest that a more gradual escalation towards FASP should be implemented initially than LOLP * VOLL (i.e. BM prices only tending towards FASP as the reserve margin is close to zero), at least on a transitional basis. Energia suggest that the precise definition of the scarcity pricing function should be determined as part of the detailed rules development.

Our position with regards to movement to a curve defined in relation to the probability of loss of load – i.e. a curve defined by LoLP * VOLL, where X would be equal to the value of LoLP at the target operating margin – is that this should only be considered if ***the following requirements relating to provision of appropriate risk management instruments are met:***

1) A liquid, transparent, exclusive and fully functional IDM to allow participants to appropriately manage exposure to energy imbalances;
2) A liquid, transparent, exclusive, centralised secondary market for ROs, with appropriate and effective market power mitigation measures, including volume obligations on dominant participants, to allow generators to manage their financial exposures associated with planned and forced outages;
3) A liquid, transparent, exclusive, centralised forward contract market with appropriate and effective market power mitigation measures, including volume obligations on dominant participants, to allow suppliers and generators to hedge their residual exposures up to the RO strike price;
4) Exemptions from RO cash outs for generators that are available but not dispatched at times of scarcity;
5) Appropriate stop loss limits to protect existing participants from bankruptcy and to remove potential barriers to financing for new investment.

As previously stated, Energia does not believe that a dynamic LOLP value should be introduced into the ASP function, as it is not clear the additional complexity will significantly improve market signals, but it will increase the commercial risks faced by generators in estimating cash outs at times of scarcity.

44)How far in advance of the start of the Capacity Delivery Year should the piece-wise linear function be set. Does this need to be before the T-1 auctions?

Significant stability in relation to the piece-wise linear function defining ASP (including the value of 'X' when ASP begins) is needed, otherwise it increases the regulatory risk associated with participating in the CRM. Changes to the piece wise linear function after an auction, but before the RO contract start date, will change the value of the cash outs required under an RO contract from the value implicitly assumed in the auction clearing price. Ideally, therefore, the function should be set prior to T-4 auctions, not T-1 auctions, to ensure CRM participants can more accurately determine their capacity bids. It is not immediately clear why this is considered impractical and therefore we suggest it be given further consideration.

Furthermore, only changes that would reduce generator cash outs under an RO contract should be implemented in intervening years, to minimise the impact of the associated regulatory risk, but we note that implementing changes in the piece-wise linear function for T-1 auctions relative to T-4 auctions will result in changes in the pricing of RO contracts, even if all other things were equal.

45)Do respondents think that any changes need to be made to the governance of the target operating reserve policy. If yes, what are these changes?

Under administered scarcity pricing the target operating reserve policy will be intricately linked with the pricing mechanism in the balancing market. Therefore it is essential that the governance arrangements for the administered scarcity price function, and the target operating reserve policy, reflect this close relationship and the impact it has on participants' commercial risks under the CRM. In particular, care needs to be taken to ensure that changes to the target operating reserve policy do not result in increased and unmanageable commercial risk for CRM participants – e.g. a change in the target operating reserve policy should not result in a change to the administered scarcity price function that increases the cash out during scarcity[36] for existent RO contracts.

2.7 Transitional issues questions

46)Which of the suggested options (annual auction, block auction, do nothing) do you prefer?

A stable transition from SEM to I-SEM is essential. Therefore ***option 3 from the consultation paper to "do nothing", is not a feasible option. It would lead to widespread disorderly exit from the all-island market, devastate investor confidence, and compromise security of supply.***

The price 'Glide Path' option, as presented by the RAs at the CRM Workshop on 29 September 2015, would however help facilitate a more stable transition to I-SEM, and also address some of the issues identified with the other options presented – i.e. the risk of inappropriate exit (under option 1) and

[36] Scarcity is here defined as any time the administered scarcity price function is in effect.

exertion of market power (under option 2).[37] We note the suggestion that it would be difficult to secure EU approval for the 'Glide Path' option but given the level of change being implemented simultaneously across all major market revenue streams, and the significant increase in complexity and market risk participants are therefore having to deal with in the transition to I-SEM, combined with the fact that such changes evidence the strong intention on the part of the relevant governments and regulatory authorities to comply with EU legislation, ***Energia believes there is a robust case for the RAs and the relevant government departments to push for measures, such as the 'Glide Path' option, that would help ensure an orderly transition to I-SEM.***

If the 'Glide Path' option is not adopted, Energia supports individual annual auctions if they are ran in line with the T-1 auction timelines – i.e. not ran "back to back" as a group. We note the significant operational and commercial risks associated with a combinatorial auction, and are cognisant of the recent experience of the GB capacity market, which demonstrates that designing a capacity market is extremely complex, and that rules can lead to unintended consequences. Therefore, ***Energia observes there is significant benefit in extending the time between the annual auction runs in the transitional period between the first T-1 and T-4 auctions, to allow time to "iron out any teething issues" with the new I-SEM capacity market.***

In support of the above position, we note the complexity and therefore potential implementation issues associated with a combinatorial auction, and the commercial risks and uncertainties it creates for participants, who will have to anticipate 4 years of how the I-SEM will operate to participate, without any operational experience of the new market arrangements (which in some areas are unique - e.g. parallel opening of IDM and BM), or how they will function in practice. We also note the potential for regulatory risk due to the concerns expressed in the Consultation Paper regarding market power.

In contrast, spread out annual auctions would reduce commercial risks on participants by allowing time to address "teething issues". Furthermore, we note that participants will take a view on future capacity prices prior to taking a decision to exit the market. The benefit of the annual option approach is that this decision remains in the hands of the generator, and not the combinatorial auction clearing algorithm. Therefore, we suggest the risk of inappropriate exit, either due to the uncertainties participants face when bidding in an

[37] For the avoidance of doubt, the "Glide Path" approach or "Option 1" do not resolve the wider market power issues that will have to be dealt with by the RAs in the CRM (and wider I-SEM / DS3 design), as discussed in section 1.2 and throughout this response. The risk of predation and low non-commercial pricing by the state-owned incumbent should also be considered by the RAs in the context of market power.

auction for a 4 year capacity contract, or as a result of unanticipated issues arising out of the CRM design, is actually higher under a combinatorial auction approach.

In the absence of the 'Glide Path' option, Energia therefore supports option 1 from the consultation paper, "auction each year separately", subject to their being sufficient time between auctions (we suggest a period of one calendar year, as per the T-1 calendar), to allow time to "iron out any teething issues" with the new I-SEM capacity market.

47)If you prefer the do-nothing option, do you believe this should be accompanied by relatively low levels of Administered Scarcity Price?

We do not support the "do-nothing" option, which effectively constitutes having no capacity mechanism for the transitional years. The continued need for a capacity mechanism in the all-island market is well-established and that is why it is an integral component of the I-SEM HLD. To abandon it now for a transitional period would cause irreparable damage to investor confidence in this market and could quickly jeopardise security of supply.

Energia again emphasises that a stable transition from SEM to I-SEM is essential. **Therefore *option 3 from the consultation paper to "do nothing", is not a feasible option. It would lead to widespread disorderly exit from the all-island market, devastate investor confidence, and compromise security of supply.***

48)Are there any other transitional issues respondents feel that we should take account of when implementing the CRM?

Yes. We have set out important transitional considerations by relevant topic below.

Cross Border Participation

Any interim arrangements for cross border participation must ensure that cross border capacity providers (whether under an interconnector led or provider led approach or a combination thereof) are subject to the same obligations to deliver (into the market procuring the capacity) at times of system stress and be subject to the same penalties for failing to deliver. This is necessary (1) to ensure I-SEM providers are competing on a level playing field and (2) to promote the objective of security of supply.

Thus for any transitional (or enduring) measure to be considered in any way acceptable from both an economic and legal perspective it must be performance based and should furthermore provide a commitment to delivery within the I-SEM.

Secondary Trading

It is essential that the RAs give careful consideration to issues of both market power and liquidity in the design and implementation of the secondary market for capacity, and we recommend that appropriately targeted liquidity promoting measures are implemented from I-SEM go live in the secondary capacity market (i.e. mandatory contracting obligations on dominant entities, such as ESB), as well as effective market power mitigation measures, to ensure there is adequate access for all CRM participants to competitively priced risk mitigation instruments.

Energia emphasises that failure to implement a functional secondary market in ROs from I-SEM go live will have significant implications for other areas of the CRM design, including stop loss limits and the design of the administered scarcity function.

Stop Loss Limits

Energia has made recommendations regarding the high-level characteristics of stop loss limits elsewhere in this response. Implementation of these recommendations will help to provide an appropriate cap on the financial exposures faced by participants, and offer some, albeit, limited protection, against potential exertions of market power. ***Energia emphasises however that they in no way undermine the need for the delivery of a functional secondary capacity market, or the other risk mitigation measures highlighted in this response.***

Furthermore, Energia cannot emphasise enough that it is essential that the design of the CRM strikes an appropriate balance between the desire for strong incentives under the RO scheme, the imposition of commercial risk, the overall level of that commercial risk, and the risk management instruments available to participants to manage their financial exposures. ***Failure to appropriately balance these aspects of the CRM design could result in market failure.***

Administered Scarcity Pricing

To avoid market failure, introduction of an administered scarcity price tending towards VOLL (i.e. at GB VOLL) is only feasible ***if the following requirements relating to risk management are met:***

1) A liquid, transparent, exclusive and fully functional IDM to allow participants to appropriately manage exposure to energy imbalances;
2) A liquid, transparent, exclusive, centralised secondary market for ROs, with appropriate and effective market power mitigation measures, including volume obligations on dominant participants, to allow generators to manage their financial exposures associated with planned and forced outages;

3) A liquid, transparent, exclusive, centralised forward contract market with appropriate and effective market power mitigation measures, including volume obligations on dominant participants, to allow suppliers and generators to hedge their residual exposures up to the RO strike price;
4) Exemptions from RO cash outs for generators that are available but not dispatched at times of scarcity;
5) Appropriate stop loss limits to protect existing participants from bankruptcy and to remove potential barriers to financing for new investment.

If these requirements are not met by I-SEM go live then introduction of an administered scarcity price that tends towards VOLL (even if set at GB levels) will impose large and unmanageable commercial risks on participants, leading to potential market failures.