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

Third Consultation Paper SEM-16-010

27 April 2016

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1. Introduction and Overview

This document sets out Energia's comments in response to the Third Consultation Paper on the I-SEM Capacity Remuneration Mechanism Detailed Design, published 11 March 2016,[1] including answers to the questions posed within that paper.

The remainder of this section 0 provides an overview of our key conclusions and section 2 discusses the governing legal framework and its implications for market design with a particular emphasis on issues pertinent to this Consultation Paper.

Sections 3 and onwards provide our comments to the questions in the Consultation Paper.

For convenience, we list our key findings and conclusions below under three broad headings: (1) Cost recovery; (2) Minimising regulatory and other unnecessary risks; and (3) Market Power Mitigation Measures.

1.1. Cost recovery

The assurance of cost recovery is essential for promoting efficient investment and remains a key concern for Energia. We discussed the legal framework surrounding this topic in our response to the SEM Committee's *Second Consultation Paper* on the *Capacity Remuneration Mechanism: Detailed Design* (SEM-15-014). We summarise that discussion in section 2 below. Several aspects of the proposed auction design place undue emphasis on limiting prices without considering the possible negative impact on cost recovery.

1. In paragraph 6.4.4, when discussing a form of market power mitigation (Option 1 - price taker offer cap), the RAs suggest that existing capacity need not necessarily receive Net CONE and that their bids can therefore be capped at recurrent costs, because existing capacity does not need to recover sunk costs to justify its continued operation. These caps would limit the industry's ability to recover its total costs, because they are likely to restrict the price of capacity in certain years (e.g. in the transitional years 2017/18 to 2019/20, before new investment enters the market, and in later years, if prices for new entrants are set in 10-year contracts). Currently, the proposals are missing any bid floors to buoy up prices in the face of predatory or "below cost" bidding. Capacity prices will therefore tend to be biased downwards. The RAs' discussion of this type of bid cap overlooks the adverse economic and legal implications of denying total cost recovery.

   In economic terms, Option 1 appears to be driven by the desire to let prices equal marginal costs, as in competitive markets. However, it ignores an important difference between the proposed capacity market and competitive markets for other products. The proposed auction rules impose an artificial

[1] Consultation Paper "*I-SEM CRM Detailed Design Third Consultation Paper*", SEM-16-010, 11 March 2016.

restriction, in that existing capacity is only allowed to bid for annual RO contracts. In a truly competitive market, whenever the market anticipated a long term shortage and an extended period of high marginal costs, existing capacity would be able to secure a long term contract at high prices. Such high priced contracts would be competitive and efficient, and would offer useful signals for investment by offering more secure opportunities for cost recovery. Such opportunities are just as important for existing capacity as for new capacity. After all, today's "existing capacity" was "new capacity" at some time in the past, and is only built on the understanding that it will have an opportunity to recover its total costs (including the cost of capital). Without such opportunities, existing capacity may be closed down prematurely, heightening the risk to security of supply.

Restricting the length of contracts available to existing capacity to one year artificially limits the ability of investors to recover their sunk costs. The capacity market must offer some alternative provision for total cost recovery, or else it will stifle competitive price signals. In practice, this alternative must take the form of allowing some flexibility for existing capacity to bid prices above their own recurrent costs.

It is not clear that there is any sound basis for distinguishing in the treatment of existing and new capacity: both are capacity, and existing capacity was new capacity when it was built. To the extent that rules are devised that distinguish between them, it is imperative that such rules do not produce discriminatory outcomes, or rely on discriminatory principles, and consistent with the statutory duties of the RAs, have due regard to the requirement that existing capacity must be capable of being financed throughout its lifetime, regardless of when it was built. This means that the rules devised should ensure that existing capacity is able to recover all of its costs and not restricted to recovering only recurrent costs. The RAs appear to consider that the CRM will involve State aid. We note that the Energy State Aid Guidelines require that in order for aid to be compatible, the scheme must "*improve the functioning of a secure, affordable and sustainable energy market*" (paragraph 49) and "*not undermine investment decision on generation which preceded the measure*" (paragraph 233). A measure which denies overall cost recovery to existing capacity and restricts existing capacity to recover recurrent costs is inconsistent with both these requirements and discriminate without valid justification between existing and new capacity.

2. The auction rules will also threaten cost recovery and efficient investment if bid caps underestimate (a) the costs of providing capacity and/or (b) the risks of participating in the capacity market. Generators will be obliged to hold ROs, which require them to pay substantial rebates at times when (for any one of a number of reasons outside their control) they may not be generating and so may not be earning any offsetting revenue from the market. Furthermore, inadequate provision for a secondary market and for mitigating market power over it will prevent generators from trading out of this situation. The RAs are proposing to cap these rebates, but at a level that would impose a net cost on generators. The risk of substantial unremunerated rebates imposes a

(recurrent) cost on participation in the RO market, which the price of capacity has to cover, creating a need for higher bids and higher outturn prices. Since the RAs have no accurate or objective method to estimate this cost, participants in the market will need some flexibility to build their own estimate into their bid prices. Setting bid prices too low would deny the recovery of this cost.

3. The RO scheme cannot function on the basis of a price cap set equal to 1x Net CONE, because it amounts to a denial of cost recovery which will discourage entry and encourage premature closures. In any unrestricted capacity market, one would expect the market price of capacity to be below Net CONE in some years, and to be above it in other years, so that expected revenue averages out over the long run at Net CONE. If the price cap is set as low as 1x Net CONE, it will guarantee that expected revenue is less than Net CONE, and that will discourage efficient investment. To offset years when the market price is below Net CONE, the market price must be allowed to rise above Net CONE in some years, or else the system is being set up to deny cost recovery with the result that it will discourage efficient investment. Furthermore, investors will be wary of relying on the correct and realistic calculation of Net CONE based on experience in the SEM where the BNE calculation has employed unrealistic assumptions (relating to WACC, plant life and IMR) which have had the effect of reducing the BNE price below market levels. We note that other schemes referred to by the RAs use a multiple of 1.5x or 2x Net CONE and that no other scheme described by the RAs applies a price cap as low as 1x Net CONE. If there are concerns about market power (but only then), the RAs may decide to cap the price, but the cap must be a set higher than 1x Net CONE, to allow for years when the price is below Net CONE.

4. As discussed above, Net CONE will be a key parameter in the capacity auction. It must be derived for the specific circumstances of I-SEM and, to minimise regulatory risk, should be objectively and transparently determined following a due consultation process. The calculation of Net CONE would have to be adjusted to allow for the expected cost of unremunerated rebates; as noted above, this adjustment must take the form of flexibility in bidding, rather than an objective cost allowance. The calculation of Net CONE must also allow for the possibility of unremunerated rebates.[2] Unless Net CONE is set appropriately, and the bid cap is set high enough above Net CONE (e.g. 2x Net CONE), the overall incentive to invest will be inadequate, discouraging entry, encouraging premature closures and threatening security of supply.

5. We are also particularly concerned by the discussion of auction pricing rules for the "marginal bid", since the proposed solutions seem to be driven more by

[2] It is unclear from the text how the calculation of Net CONE will allow for the difference between the plant life of the plant concerned (e.g. 20 years) and the length of contract being offered to new entrants (up to 10 years). Giving new entrants security of cost recovery would require the Net CONE to be calculated over a 10-yar plant life.

a desire to depress prices, than by the need to promote efficient investment by finding a competitive, market-clearing price.

- In paragraph 5.6.5, "Approach 2" would take the price for most of the market from a set of bids that are simply insufficient to meet the capacity requirement, as defined by the demand curve; selecting such a price would be arbitrary and perverse.
- The selection process named as "Option 3b" in paragraph 5.6.8 (as "net *consumer* welfare") and depicted in figure 11 (RHS) simply applies the monopsony of the single buyer to depress prices by restricting demand. It accepts a quantity of bids set deliberately below the capacity requirement and takes a (lower) outturn price from this restricted quantity of bids; it then accepts a higher priced "marginal bid" to match supply to the capacity requirement, but does not in any way reflect the cost of this marginal bid – i.e. the marginal cost – in the auction price paid to other bids. The price setting rule in Option 3b discriminates between the marginal bid and the other bids without good reason or justification where other, non-discriminatory solutions are possible (as we demonstrate below). The explicit restricting of demand to depress prices produces an outcome which does not in any way mimic the efficient outcome of a competitive market and is therefore inconsistent with the RAs' statutory objectives and the promotion of competition.

As we show below, it is possible to set auction prices that reflect the marginal cost of supplying the capacity requirement (not some arbitrarily set quantity below it.) Only solutions based on matching supply to demand (and selecting marginal bids on the basis of *social* welfare or similar simplified rules) will give signals for efficient investment to serve consumers.

6. The setting of the RO strike price with reference to monthly fuel indices would guarantee that certain generators do not recover their costs whenever spot fuel prices are significantly above the referenced month ahead index price, even if the generator has been dispatched in the energy market during a scarcity event – i.e. the generator's energy payment would be capped by the RO strike price at a level that is below its SRMC. This risk is particularly acute for gas fired generators, if ASP pricing is introduced into the GB gas market, and would drive up the market price of capacity (and also any caps and floors on bids) to cover the associated costs of generating at a loss. To minimise this risk and its associated costs, the strike price for ROs must therefore be set with reference to spot fuel indices (as set out in our answer to question 8B below).

7. Finally, the discussion of "difference payments socialisation arrangements" in section 8.3 also gives no consideration to the ability of suppliers to efficienct recover the socialised charges. The proposed methods in the consultation paper for managing any shortfall in the socialisation fund impose unmanageable risks on suppliers which is damaging to retail competition and the consumer who will ultimately bear the cost of this inefficiency. In this

response, we suggest an alternative solution that does away with these issues and complies with the principle of cost recovery.

For the legal framework of regulation relating to cost recovery, see section 2 below.

1.2. Minimising regulatory and other unnecessary risks

As stated in the previous section, the market price of capacity must cover the cost of all risks facing the holders of ROs and it would therefore be advisable to minimise the extent of these risks whenever possible. To achieve that aim, the RO Strike Price must be set above the cost per MWh of every generator running at times of system stress (including all costs, such as gas capacity, start-up and part-loading), to avoid unpredictable rebates. To minimise risk the RO system must also consist of objective formulae that use publicly available data, and it must be governed by a transparent procedure that prevents arbitrary changes to those formulae. We elaborate on what is required to meet these conditions below.

RO Strike Price: Meeting these conditions means that the strike price in the ROs must be set at least as high (and possibly higher) than the costs of the highest priced generation capacity operating during a system stress event. That generation capacity may not correspond to the "Best New Entrant", or even a peaker unit, but rather could be a CCGT that needs to recover its total costs over a short time horizon. These total costs include not just fuel costs, but charges for gas capacity (or the cost of delivering other fuels), start-up costs and the cost of part-loading (if for technical reasons the generator has to start before, and continue running after, the period of system stress). The statement denying the need for cost recovery in paragraph 8.2.2 is incorrect, and particularly inapplicable in system stress conditions when the I-SEM rules must provide a commitment to cover start-up costs (regardless of whether a plant runs for one hour or longer) to ensure the incentive to generate is maintained.[3] The proposed formula must therefore be adapted to cover all these costs either by their explicit inclusion (which is our preferred approach), or by setting an efficiency value that is demonstrated to be sufficient to meet the objectives set out above.

The reasons for setting a relatively high strike price are as follows.

- In any electricity market, a short-lived peak in demand (or in the net demand met by non-intermittent generators) can lead to expensive capacity being despatched out-of-merit, because other, cheaper capacity is unable to respond in time. This risk is exacerbated by the lack of experience with EUPHEMIA as a scheduling tool and the fact that there is no provision for

[3] Paragraph 8.2.2 states "There should not be any commitment that all plant should be able to recover its start-up costs under all circumstances, and it is not very likely that much plant would be required to start-up and run for only one hour." However, this statement does not apply in periods of system stress, because they are precisely the times when the I-SEM rules must provide a commitment to cover start-up costs (regardless of whether plant runs for one hour or longer) to maintain the incentive to generate. We cannot actually envisage any conditions in which a plant should be denied the chance to recover its start-up costs, if it is running in-merit or is despatched out-of-merit by the system operator.

direct self-scheduling in the I-SEM energy trading arrangements.[4] If ROs were called at such times, the non-despatched, cheaper capacity would find itself substantially out of pocket.

- On the other hand, if the strike price is set too low some generation capacity – i.e. the plant with the highest short run marginal costs (SRMC) over the duration of a short scarcity event – may not be generating at times when ROs are called. This could occur if the strike price is tied to a value of SRMC derived from other capacity with lower costs, or if the strike price is set using monthly fuel price indices, which do not reflect short term volatility in spot market pricing.

In both these cases, generators face the risk of making rebates under their ROs without earning any revenue to offset them. This risk would drive up the market price of capacity (and also any caps and floors on bids) to cover the associated costs. To minimise this risk and its associated costs, the strike price in ROs should be set at – or above – the market price likely to apply during periods of system stress when every unit of generation capacity is more likely to be running.[5] That price is best defined by the total costs of the most expensive generator that could be required to run during a short-lived period of system stress. These total costs include not just fuel costs, but charges for gas capacity (or the cost of delivering other fuels), start-up costs and the cost of part-loading.

Governance: If the RO scheme is to provide an incentive for efficient long term investment, it must be a stable and predictable system. Arbitrary changes to the rules will undermine its ability to provide efficient incentives and increase regulatory risk. The scheme must therefore – from the very outset – comprise well defined rules for defining all its procedures and parameters, and for making any required subsequent changes to them, including (but not limited to):

- A commitment to transparency and consultation;
- The identification of a capacity requirement for each T-1 and T-4 auction;
- The conversion of this capacity requirement into a sloping demand curve, using public data on real plant sizes and costs to define the gradient;
- The de-rating of capacity and the definition of capacity for demand-side resources;
- The targeting of market power mitigation measures;
- The selection of the marginal bid and the derivation of the auction price for other ("inframarginal") bids;
- The calculation of the RO Strike Price by reference to the total costs of the most expensive generator that could be required to run during a short-lived period of system stress;

[4] The ability to submit a non-zero PN independently of a generator's traded position in ex-ante markets.

[5] A residual dispatch risk still remains in this scenario heightened by the design of the energy trading arrangements, which mean a generator must trade itself into a dispatch position via ex-ante markets.

- Definition of stop-loss limits;
- The definition of any price caps, including the calculation of Net CONE for the relevant type of plant (not in current conditions, but for the date of the auction in 1 to 4 years' time).

The purpose of the CRM is to provide greater revenue security to existing and future investors. Unless it is made stable and predictable in this manner, the CRM will simply fail to fulfil its intended purpose.

1.3. Market Power Mitigation Measures

As in other parts of the I-SEM, the RAs should only implement Market Power Mitigation (MPM) measures if they address an identified problem and are targeted on the market participant(s) at the source of the problem. The design of effective MPM measures seeks to balance (1) the costs of under-regulating and failing to prevent an abuse of dominance against (2) the costs of over-regulating and prescribing inefficient bids by regulatory fiat. Imposing MPM measures on a market-wide basis, whenever measures targeted at the dominant supplier are sufficient to address the issues arising from dominance and prevent the abuse of dominance, would be disproportionate and unjustifiable. The risk of under-regulation arises only where partial bidding controls might not cover parties likely to have significant market power. In an oversupplied market like the I-SEM, with only ESB as a dominant player or market leader, only targeted mechanisms which cover the pivotal provider(s) are appropriate as they are sufficient to target and address the source of this issue and reduce the risk of over-regulation.

We see no possible justification for market-wide restrictions that would affect all or most market participants. Such wider MPM measures would be disproportionate and as such will hamper competition, rather than promote it.

In the light of this principle, we have the following comments on specific aspects of the RO market.

1. The RAs have yet to complete their tests for market power in the CRM. However as referenced in our earlier submission[6], there can be no doubt that ESB clearly still has a dominant position in the wholesale, forward and retail markets, by any of the recognised structural tests (HHI, PSI, RSI). In contrast, there is little evidence that any other market participant possesses significant market power. In the context of the I-SEM, the recognised tests can only be applied to single firms. Given that ESB is dominant, any test that combines ESB with one or more other firms will always indicate the presence of dominance, but such tests provide no evidence that the firms(s) other than

[6] See for example, Response by Energia to Consultation Paper SEM-15-094, I-SEM Market Power Mitigation Consultation Paper, 18 January 2016, page 21.

ESB contribute towards it.[7] Multi-firm tests therefore provide no justification for extending MPM measures to market participants other than ESB.

2. The temptation to over-regulate the market will be strongest in the transitional years, because of the possible lack of new entry. However, holding prices too low is one way to guarantee that no-one else enters the market (and existing players leave the market prematurely), which would harm consumers' interests. In practice, existing capacity will face competition in the transitional years from excess supply (i.e. from the possibility of delaying planned exits) and from the sloping demand curve. If applicable, the slope in the demand curve should be defined by reference to specific plants (chosen for their relevance to a market the size of the I-SEM, e.g. OCGTs), thereby creating an equivalent to competitive new entry.

3. Most importantly, the Third Consultation Paper recognises at many points the possibility of predatory or non-commercial bidding (which is particularly pertinent in the all-island market with a dominant state-owned incumbent), but fails to propose any suitable remedies. If these firms have enough market power to raise prices paid by consumers, they will also have enough market power to lower the prices earned by their competitors. Remedies therefore have to be symmetric, when applied to one of these firms: for every bid cap, there must be a corresponding bid floor. The concept of bid floors is applied in many US markets because of the fear of under-pricing (particularly by the buy-side). Conditions in the I-SEM however mean that these concerns manifest themselves on the sell-side and therefore a remedy that is specific to the I-SEM is required. At the workshop on 16 March, we heard suggestions that the EU State Aid guidelines rule out price floors in capacity auctions. Whether or not this is the case, in any event and to the extent that there is aid involved, the Guidelines do not rule out all defences against predatory pricing. In this regard, the placing of a floor under the *auction clearing price* may be inconsistent with the principle of a competitive bidding process, since that would constrain the outcome of a competitive market. However, there can be no objection to placing a floor under *individual bids*, with the intention of preventing predatory behaviour and anti-competitive outcomes.

Thus, at each point in the decision-making process, it is essential to ensure that MPM measures are used to encourage a competitive outcome in the capacity auctions (and in secondary markets), and do not merely depress the prices earned by investors.

[7] The situation is different in markets where no single firm is dominant. In such markets, multi-firm tests may provide additional information.

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 that its actions as an administrative authority are subject to similar general legal principles. All references to the legal framework in this section should be read accordingly.

2.1. Legal Framework

As explained in Energia's response to the SEM Committee's *Second Consultation Paper* on the *Capacity Remuneration Mechanism: Detailed Design* (SEM-15-014), a number of key legal requirements, summarised below, are particularly relevant to the design of I-SEM:

- In their decision-making, the regulatory authorities subject to public law principles. In particular, 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. Regulatory measures must be proportionate, that is, both *suitable* and *necessary* to achieve the aim pursued and where they affect a constitutionally protected right –impairs that right as little as possible. This is reflected in the objective set for the Minister and RAs by section 9BD of the Electricity Regulation Act, 1999 in respect of the SEM that the performance of their functions should be "*transparent, accountable, proportionate, consistent and targeted only at cases where action is needed".* These principles are also directly relevant to the design of I-SEM and the CRM.
- 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.[8] Note that regulating prices to ensure that they are "competitive" does not mean to ensure that they are the "lowest achievable by any means", but rather that regulation works to ensure that the prices achieved in the regulated market most closely approximates the competitive market price. This is consistent with the principal statutory objective of the RAs under section 9BC of the Electricity Regulation Act, 1999 in relation to the SEM, namely "*to protect the interests of consumers of electricity in the State and Northern Ireland supplied by authorised persons, wherever appropriate by promoting competition between persons engaged in, or in commercial activities connected with, the sale or purchase of electricity through the Single Electricity market"* and there is no reason why the objective pursued by I-SEM should be any different.

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

- The measures adopted by the RAs should, consistent with Directive 2005/89/EC of 18 January 2006 concerning measures to safeguard security of electricity supply and infrastructure investment, ensure a high level of security of electricity supply by taking the necessary measures to facilitate a stable investment climate which measures should be non-discriminatory and not place an unreasonable burden on the market actors. They should encourage the establishment of a wholesale market framework that provides suitable price signals for generation and consumption.
- The measures adopted should be consistent with the statutory duty of the CER and the Minister 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. In accordance with European State aid law, State intervention in the market should be 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.[9]
- Regulatory measures, consistent with competition law including 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, should recognise 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 Mechanism, DS3 System Services, Administered Scarcity Pricing, energy market bidding restrictions, obligations in secondary contract markets, 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

[9] European Commission, Communication of 5 November 2013, *"Delivering the internal electricity market and making the most of public intervention*", C(2013) 7243 final.

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.

2.2. Implications for Market Design

Measures that are currently under consideration by the RAs, including in particular the rules regulating bids into the capacity market, directly and significantly affect 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 would amount to a form of unconstitutional expropriation.

The market design chosen and some of the market power mitigation measures consulted upon imply a high risk of inefficient and inappropriate exit signals being generated from the capacity market. Several of the proposals considered in the Consultation Paper appear to be favoured merely because they produce *low prices*, rather than *competitive market pric*es. It is imperative that the regulatory measures finally adopted address these risks in full, in accordance with legal requirements and the duties of the RAs.

We have in response to previous consultations highlighted the risk that the RAs, treating the various strands of I-SEM independently of each other, produce a fully developed set of rules which does not allow generators to finance their activities contrary to legal requirements and to the detriment of the very objectives being pursued, namely competition and/or competitive outcomes and security of supply.

In particular, any combination which exposes 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 discourages both the construction of new generation capacity and the maintenance of existing generation capacity (including generation capacity required for system security). It therefore threatens security of supply.

For the CRM Workstream, 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 their total costs, including the cost of the *risks* of holding Reliability Options, would amount to an unreasonable suite of measures which would be not only unsuitable to achieve the objectives pursued but would work against delivering competitive outcomes and security of supply.

2.3. Implications for CRM Workstream

In the context of a capacity scheme that will be mandatory for dispatchable generators,[10] 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 will have to meet the following conditions:

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” or “bid cap” that will apply in the RO auctions does not prevent capacity providers from bidding prices commensurate with recovering their total costs, including the cost of the risks of holding Reliability Options;

5. Apply properly targeted market power mitigation measures (in the form of appropriate “bid floors”) 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, or – given that creation of a liquid market may not be possible give the structural issue in the I-SEM (e.g. the increasing volume of intermittent wind generation) – to expand the volume of the Directed Contracts or similar obligations imposed on ESB;

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

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 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);[11]

9. In the event that exit signals are appropriately received by plant, it is imperative that the obligations placed on that plant (for instance through its generation licence or the Grid Code) allow exit in the same timeframe as the signal given by the market;

10. Review (1) the Outturn Availability Decision (SEM-15-075), published 29 September 2015, and (2) 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, via either ex-ante or balancing markets, regardless of network outages.

[11] 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.

3. CRM III Questions – Section 3

Below, we set out our response to the questions in section 3 of the Third Consultation Paper. Where appropriate, we refer back to our comments in sections 1 and 2.

3.2.1 Do respondents agree with the proposed approach for transitional auctions, T-4 auctions and T-1 auctions? If not, please explain.

Our main conclusions on auction design are set out in section 1.1 on cost recovery and section 1.2 on risk minimisation.

With respect to the auction timing, we have a key concern with the proposal to start the capacity year on 1 October each year as this means holding the auctions just 3 months prior to the delivery period. This is neither practical nor desirable given that some generators may be unsuccessful in the auction and may wish to retire within the 3 month period.

The Consultation Paper provides insufficient clarity in relation to the method for determining the capacity requirement generally and raises a particular concern in paragraph 4.7.14 that the capacity of retiring plant would be deducted from the capacity requirement in the T-4 auction to reflect their non-participation. In light of the need for stability and predictability, some aspects will therefore require further consultation, including (but not limited to):

- The method of determining the Capacity Requirement for the T-1 and T-4 auctions needs to be clarified, to remove regulatory risk. Changing the basis of the Capacity Requirement would have a big impact on pricing outcomes and cannot be left to the judgement of regulators, industry managers or supposed experts.
- Likewise, there is a need for further consultation on the definition of the volumes reserved in each auction for Demand Side Resources (DSR). Overstatement of DSR would depress auction prices and threaten security of supply.

We expect to see further consultation on the selection of methods for defining Capacity Requirements and DSR capacity, using objective formula and publicly available data.

3.2.2 What is respondent's view in relation to the flexibility around the timing of the T-1 and T-4 auctions?

Paragraph 3.1.15 notes that "within GB their T-1 auction can be held anytime within a period ranging from 13 months to 2 months before the start of the delivery year". We would be concerned if the T-1 auctions only took place toward the end of this period. To facilitate time to carry out any required actions following the capacity auction the calendar should allow *at least* six months after the T-1 auctions for the system operator to review auction outcomes and to organise any alternative contracts.

4. CRM III Questions – Section 4

Below, we set out our response to the questions in section 4 of the Third Consultation Paper. Where appropriate, we refer back to our comments in sections 1 and 2.

4.8.2 Do respondents agree that market power is a material concern in the I-SEM CRM? If no, why not? Should the SEM committee be concerned with unilateral market power, the potential for collusion or both?

We agree that market power is a valid concern in the I-SEM CRM, but the solution to market power discussed in the Third Consultation Paper would under-regulate some aspects and over-regulate others. Further work is required to ensure that the MPM measures are properly targeted so as to be effective and proportionate.

Buy-Side Market Power and Predatory Pricing

Paragraph 4.1.6 suggests that the main concern is with "sell-side" market power and with attempts to withhold capacity to drive up prices. However, the experience from US capacity markets shows that creating a single buyer does not eliminate the possibility of "buy-side" manipulation of the market to depress prices.

Most importantly, the Third Consultation Paper recognises at many points[12] the possibility of predatory or non-commercial bidding (which is particularly pertinent in the all-island market with a dominant state-owned incumbent[13]), but fails to propose any suitable and effective remedies. If these firms have enough market power to raise prices paid by consumers, they will also have enough market power to lower the prices earned by their competitors. Remedies therefore have to be symmetric, when applied to one of these firms: for every bid cap, there must be a corresponding bid floor.

The concept of bid floors is applied in many US markets because of the fear of under-pricing (particularly by the buy-side). Conditions in the I-SEM however mean that these concerns manifest themselves on the sell-side and therefore a remedy that is specific to the I-SEM is required. At the workshop on 16 March, we heard suggestions that the EU State Aid guidelines rule out price floors in capacity auctions. Whether or not this is the case, in any event and to the extent that there is aid involved, the Guidelines do not rule out all defences against predatory pricing. In this regard, the placing of a floor under the *auction clearing price* may be inconsistent with the principle of a competitive bidding process, since that would constrain the outcome of a competitive market. However, there can be no EC

[12] Several paragraphs in the Third Consultation Paper recognise incentives for bidders on the sell-side to depress prices through "below cost bidding" or "predatory pricing" (paras 4.1.9, 4.3.4, 4.3.9 and 4.7.35). We welcome these references.

[13] The key consideration here is that State-owned firms, and ESB in particular, do not always maximise their profits. Such firms can be motivated by other political or managerial aims to engage in "below cost bidding".

objection to placing a floor under *individual bids*, with the intention of preventing predatory behaviour and anti-competitive outcomes.

Unilateral Action versus Collusion

As discussed in section 1.3 above, effective MPM measures balance the costs of under-regulating against the costs of over-regulating. We are not aware of any evidence of collusion, explicit or tacit, and there is no reason to believe that it will be a feature of the I-SEM capacity market. Imposing measures to prevent collusion would therefore cause the market to be substantially over-regulated.

It is easy to find accusations of collusion in the spot and forward electricity markets of other countries, where there are several large players. However, the structure of the I-SEM and its capacity market is quite different. First, there is only one dominant player and the other companies have small market shares. In such a market, the dominant player can pursue its aims unilaterally, without any need for collusion. Second, the dominant player, being state-owned, has different interests from the other companies, making collusion unlikely. Indeed, collusion would be impossible if ESB faces pressure to depress prices, as it would harm the interest of other generators. Collusion is therefore both unnecessary and unlikely in the I-SEM capacity market, regardless of possible occurrences in other countries, because ESB has unilateral market power, and notwithstanding, may be incentivised to pursue non-commercial objectives.

When assessing which firms have market power in the context of the I-SEM, pivotal supplier tests (PSI and RSI) highlight the dominance of ESB and provide no further information when applied to two or three firms. They do not indicate whether or not collusion is likely – they merely confirm ESB's dominance. Thus, there is no threat of under-regulation in focusing bid caps or floors on firms identified as having unilateral market power.

Indeed, given the novelty of the I-SEM capacity market and the difficulty of calculating the costs of capacity, trying to apply bid caps or floors to every potential supply amounts to over-regulation. It would require the RAs to investigate the cost of providing capacity from each unit of each provider, and to reach a detailed understanding for each unit of each type of cost involved, including not only its operating costs but also the expected cost of risks such as unremunerated RO rebates. Trying to apply such approaches universally (rather than targeted on individually dominant or pivotal providers) would entail a great deal of work by the RAs, and yet would still expose the market to the risk of inaccurate cost estimates and distorting the auction outturn price, with adverse implications for security of supply and competition.

A well balanced set of MPM Measures would therefore focus on the control of those providers with unilateral market power, and would include measures to prevent "below cost bidding" by ESB and its affiliates, at least.

4.8.3 Do respondents think that the overall market power control framework and package of mitigation measures set out in this section is comprehensive

and proportionate? Are there any additional market power concerns that the SEM Committee should be focussing on? Should the SEM Committee bar any existing firm transmission access intermittent generator which has opted out of an auction (on grounds of retiral) from bidding in subsequent auctions, if it subsequently does not retire and/or apply other sanctions?

The package of MPM measures discussed in the Third Consultation Paper is not comprehensive, since it omits any suitable remedy for "below cost bidding" by ESB and its affiliates. This omission is a major one and will require further work in this workstream.

As discussed above, suggestions that MPM measures should be market-wide and/or should tackle potential collusion are disproportionate. Such interventions would entail over-regulation and hinder competition instead of promoting it.

As for plant retiral, the auction rules must anticipate the possibility of unforeseeable changes in market conditions that cause the owners to reverse their decision to retire a generator. The flexibility to prolong the life of a generator promotes competition and it would be counter-productive, as well as disproportionate, to ban or penalise every such decision.

In practice, hardly any of the generator companies (apart from ESB) have any non-competitive incentive to withdraw plant from the capacity market, since they have few, if any, other units with which to capture higher prices. Therefore, rather than trying to develop some market-wide restriction that covers all cases, the RAs should concentrate on plant retirals by ESB while allowing efficient exit decisions.

4.8.4 Do you think that firm transmission access plant which has bid at a certain point within the tolerance band in the T-4 auction (below the maximum) should be allowed to bid more capacity (up to the top of the tolerance band) in the T-1 auction?

Generators will be able to bid more efficiently in a T-4 auction if they know they can manage their RO obligations via a secondary market. If a liquid secondary market is unlikely to develop, it would seem prudent to allow generators some flexibility to manage their RO positions by allowing them to offer uncontracted volumes (up to their maximum de-rated level) in T-1 auctions.

Since the appropriate choice of rules depends on the likelihood of a secondary market in ROs developing in the near future, it would be useful to consult on this topic later in the year.

Our initial view is that creating a secondary capacity market will require special measures to be imposed on ESB and, even then that the secondary market may not develop because of the small size of the I-SEM and the mandated nature of participation in the CRM. It would therefore seem prudent to provide generators at least some flexibility to manage their RO position.

4.8.5 What metrics should be used to assess whether a capacity provider is dominant, for the purpose of either applying other Bid Limits and/or controls

on aggregation (the approach to setting the level of bid controls is discussed in section 6)?

As stated in section 1.3 above, measures such as Bid Limits and controls on aggregation need to be targeted on the firms that might otherwise distort competition, and would be disproportionate and a hindrance to competition if applied to every market participant, regardless of their circumstances. We agree with the tentative conclusion in paragraph 4.6.3 that ESB will have market power in the auctions. We note that only ESB and SSE fell below the threshold level of 1.2 for the RSI test as applied to the energy market (Market Power Consultation Paper SEM-15-094, paragraph 6.4.8).[14] We can see no evidence that any other generators have market power sufficient to require further controls of the capacity market.

Paragraphs 4.5.10-11 discuss the Two Pivotal Supplier Test and the Three Pivotal Supplier Test, but reach a conclusions that is incorrect. The RAs note that, assuming ESB was pivotal by itself, all participants would fail the Two and Three Pivotal Supplier Test. However, contrary to the conclusion in paragraph 4.5.11, the failure of these tests does *not* provide any basis for applying “a whole suite of market power controls to all bidders, not just individually dominant bidders”. Instead, it only confirms that ESB is pivotal.

In a market where one player is pivotal, the Two and Three Pivotal Supplier Tests will always identify all other players as jointly pivotal, regardless of their size or market power. If the market cannot clear without ESB, then obviously it cannot clear without ESB plus one or two other players. However, that result provides no information about the other players’ potential to abuse market power, and so provides no basis for extending controls to cover them. The other players might have very small shares of total capacity and no market power at all. Identifying them as pivotal would be misleading. Imposing controls on them would lack any analytical justification and would be a disproportionate response.

The Two and Three Pivotal Supplier Tests are directed at markets where the simple tests find that *no single firm* is dominant or pivotal. Finding that two or three firms might be *jointly* pivotal then provides additional information that might be useful in designing controls. That is not the case in the I-SEM.

The I-SEM will be dominated by a single leading firm and will have a broadly competitive fringe. That market structure provides support for targeted market power mitigation measures, covering individual players with market power, but it provides no justification for market-wide controls.

4.8.6 Do you agree that dominant /pivotal generators should be prohibited from acting as Capacity Aggregators? Should associated businesses of

[14] The RAs have already applied the RSI test to the energy market. With regard to the capacity market, the RSI test does not seem to impose “unnecessary complexity” (paragraph 4.5.12), unless it provides no information on the existence of market power over and above that provided by other indicators.

dominant / pivotal generators (e.g. their Supply arms) also be prohibited from acting as Capacity Aggregators too?

Since the RAs have not yet defined which firms are dominant/pivotal, we cannot comment on the effect or proportionality of a prohibition on such firms acting as Capacity Aggregators.

The RAs have not decided how they would apply the results of pivotal supplier tests for individual firms. However, we do not regard any firms other than ESB as dominant, and explained above why Two or Three Pivotal Supplier Tests would give a misleading indication of the firms that are pivotal in the I-SEM.

Given the clearly dominant position of ESB in the capacity market we can however see the obvious rationale for preventing ESB and its affiliates from bringing an even broader range of capacity under its control, either by prohibiting it from acting as a Capacity Aggregator, or by so circumscribing its performance of this role that it cannot exercise any influence over it. However, we believe that competition would be harmed by extending such a prohibition, or similar restrictions, to other firms.

4.8.7 Should there be a prohibition on ESB and other dominant generators providing aggregation services?

See answer to previous question.

5. CRM III Questions – Section 5

Below, we set out our response to the questions in section 5 of the Third Consultation Paper. Where appropriate, we refer back to our comments in sections 1 and 2.

5.9.2 Which auction format (simple sealed bid, multiple round descending clock, combinatorial format, i.e. Option 1 to 3 in Section 5.2) do you think is most appropriate for the transitional auctions, T-4 and T-1 auctions, and why?

We support the adoption of either a sealed-bid or a descending clock auction, both of which regulators have adopted internationally. However, given the specific characteristics of the I-SEM capacity market we prefer the sealed-bid auction format.

The SEM Committee has stated that market power controls are simple and easy to apply in a sealed-bid format (paragraph 5.2.22). However, given the dominance of ESB in the I-SEM, the RAs cannot rely on the auction format alone to control market power (see CRM III Questions – Section 4, above).

We agree with the RAs' suggestion that, in the context of a single product auction, a combinatorial auction "offers little benefit to the bidder" (para 5.2.29) – which means it offers little (if any) benefit to the buyer, since it will not lead to lower prices. In practice, bidders can express their preferences as price-quantity pairs, in either (1) a descending clock format or (2) a sealed-bid format that allows bidders to submit a supply curve. Moreover, given ESB's dominant position in the I-SEM, the key drawback of the combinatorial auction is particularly relevant: combinatorial auctions for different services offer the potential for ESB to extend its market power from one service to another. Accordingly, a combinatorial auction would not lead to more efficient, competitive outcomes in the I-SEM capacity market.

5.9.3 Do you have any preference for the structure of bids for the auctions? Explain your rationale.

Energia is concerned that Option 2 in section 5.3 of the Consultation Paper could unnecessarily increase the complexity of the auction and may provide greater opportunity for dominant players to exert market power. It is also not clear what the benefits of implementing Option 2 would be, as the requirement for multiple PQ pairs to be monotonically non-decreasing may not accurately reflect the shape of the capacity cost curve. Energia therefore recommends that Option 1 is adopted – i.e. a simple PQ pair approach.

5.9.4 Do stakeholders agree with the proposed approach of adopting Option 3b to deal with the lumpiness/discrete bid problem? If not, please explain why not, and your preferred alternative approach.

We do not agree with the adoption of Option 3b, given the explanation of it in Figure 11. It is inefficient, anti-competitive, discriminatory and opportunistic. We explain why here, and set out an alternative solution in our answer to the next question.

Option 3b, or "net consumer welfare" (i.e. maximising consumer surplus), is not an efficient standard to apply when deciding whether or not to accept out-of-merit bids. According to Figure 11, the assessment by this standard considers not only the costs of the marginal bid, but also its impact in reducing the prices paid to inframarginal bids. That may lead to unnecessarily expensive bids being accepted at the margin, because they cause a bigger reduction in prices paid to inframarginal bids.

- The increased cost of the marginal bid is inefficient;
- considering the price paid to inframarginal bids is a straightforward application of the monopsony (single buyer) model of procurement, and so is anti-competitive;
- since it pays a lower price to inframarginal bids than to marginal bids, without any objective justification for this different treatment, this rule is discriminatory;
- to the extent that the rule is justified by the desire to lower prices, it is opportunistic and damaging to security of supply.

Option 3b disadvantages all but the marginal bid for capacity, by depressing the price below competitive levels. Such policies harm the prospects for cost recovery, discourage new entry, encourage premature closures, and threaten security of supply.

These effects are likely to be substantial, given the size of lumpiness problem in relation to the small scale of the I-SEM.

5.9.5 Do stakeholders agree with the approach of setting the clearing price based on the highest accepted in-merit winner, and paying any out-of-merit winners based on a pay-as-bid basis? If not, please explain why not, and your preferred alternative approach.

Energia does not support this proposal and our reasoning for this is set out below in two parts. First, we discuss the proposal to use a combination of pay-as-clear and pay-as-bid prices. Second, we consider the proposal to take the pay-as-clear price from the "highest accepted in-merit winner".

First, the academic literature tends to support the choice of a pay-as-clear auction as opposed to a pay-as-bid auction in a variety of contexts, for the following reasons among others:

(1) bidding in a pay-as-clear auction only requires the bidders to know their own costs (or valuation) of providing the product in question. Bidding in a pay-as-bid auction requires bidders to work out what they think other bidders will bid in order to optimise their decision making, which is not only a more difficult task (implying higher administrative costs), it is also more prone to errors;

(2) in a pay-as-bid format, the ultimate allocations may be inefficient because bidders who guess other bidders' prices incorrectly may bid prices that are too high, and fail to win contracts, even if they have the lowest costs. Such

inefficiency increases prices overall, by preventing the selection of least-cost producers.

The pay-as-clear format therefore has advantages in terms of lower administrative costs for participants and a lower probability of cost-raising inefficiency due to errors. Energia therefore strongly favours a pay-as-clear approach.

Second, we find the stated reasons for choosing a "first-price" auction to be flawed and therefore inadequate, since a "second-price" auction offers some advantages as a possible solution to the lumpiness problem.

The selection of the pay-as-clear price from the "highest accepted in-merit winner" accords to the "first-price" auction model. Taking the pay-as-clear price from the "lowest rejected out-of-merit loser" accords to the "second-price" auction model. The reasoning behind the choice of Option 1 ("first-price") rather than Option 2 ("second-price") is set out in paragraph 5.5.3:

2) "It could be argued that in an imperfectly competitive market, paying highest accepted offer also creates some weak incentives for a bidder to bid up to a value just below the cheapest rejected offer. However, this incentive only exists if a bidder expects it has a reasonable probability of being the most expensive accepted offer, since only the most expensive accepted offer will affect the clearing price. The variant of uniform pricing where the clearing price is set at the cheapest rejected offer removes even this weak incentive to bid up to the price of the next bidder in the merit-order. *However, it comes at the cost of paying a higher price – a price greater than any of the providers require to provide the service. This pricing format is therefore rejected on efficiency grounds*." *[Italics added]*

There are several flaws in this line of argument.

The RAs state that bidders will only have an incentive to increase their bids if they have a "reasonable probability" of being the most expensive accepted offer. Following the RAs' logic, bidders who knew they were likely to be inframarginal could bid any price below the predicted clearing price (e.g. zero) because they would not expect to set the price in the auction and would want to obtain a contract. However, this style of bidding is not often observed, because the world is uncertain. In practice, the optimal bidding strategy for all bidders is to set their bid price taking account of the possibility that they will set the price in the auction, however unlikely that may be.

This strategic insight illustrates how "first-price" and "second-price" auctions come to be revenue equivalent (see section **Error! Reference source not found.** above):

In a first-price auction, bidders will bid up to their expectation of the next most expensive accepted offer. The clearing price is set by the marginal winning bidder, who bids a price equal to their expectation of *the price bid by the marginal losing bidder*.

In a second price auction, bidders bid prices equal to their own underlying cost or valuation of providing the service. To incentivise such truth-telling behaviour, the auction rules must set a clearing price independently of any winning bids, and above that of the marginal winning bidder. The lowest possible price that fulfils these conditions is *the price bid by the marginal losing bidder*.

Therefore, provided that the marginal winning bidder has rational expectations, first-price and second-price auctions are expected to produce exactly the same outturn prices, namely the marginal cost of expanding supply by accepting the next most expensive bid. It is therefore incorrect to argue that a first-price auction will result in a lower price, or a more efficient outcome, because it avoids the "cost of paying a higher price" (para 5.5.3). It is also incorrect to suggest that a first-price auction avoids the need to pay "a price greater than any of the providers require to provide the service" (para 5.5.3), since that is not certain (it depends on the gap between the marginal winning bid and the marginal losing bid).

Since the expected outturn price is in any case common to both first-price and second-price auctions, it provides no basis for distinguishing between them.

In contrast, the first-price auction is likely to be less efficient than the second-price auction if, as is likely, the marginal winner is less able to estimate the marginal loser's costs than his or her own costs. Energia therefore strongly favours a "second-price" auction.

5.9.6 Should the SEM Committee introduce a sloped demand curve, either as a market power control, or for other reasons?

In theory, a sloped demand curve will reduce market power and the need for regulating capacity market bids. We therefore see some advantages in a sloped demand curve – but only on condition that one can be defined without injecting additional regulatory risk and opportunism through manipulation of the demand curve parameters.

A sloped demand curve diminishes the incentive for individual market participants to hold up the price of capacity by withdrawing small amounts of plant, because it reduces the potential for any player to benefit from higher prices and hence higher profits on its remaining portfolio. We note however that only ESB would be in a position to adopt such a strategy in the I-SEM capacity market as they own the only large generation portfolio.

A sloped demand curve may not entirely eliminate the incentive for dominant firms to exert market power. For example, a sloped demand curve is likely to be totally ineffective in preventing predatory or "below cost" pricing by firms that are not profit-maximising. Therefore, we expect the need for appropriately targeted market power mitigation measures to persist in the I-SEM, even if there is a sloped demand curve, particularly to guard against the risk to competition of "below cost bidding". .

Sloped demand curves have other advantages, such as more realistically reflecting the social value of capacity. The social value of capacity is unlikely to fall immediately to zero on reaching a capacity target, but it tends to be lower/higher when security of supply (i.e. the level of capacity) is higher/lower. Around the capacity target, this variation in value would be broadly symmetric for increases and decreases in capacity. However, it may be necessary to assign a steeper gradient on the demand curve below the target level of capacity than above it. A steep curve on the down side of the capacity target will ensure that any shortfall in capacity is quickly offered a strong incentive to build new capacity, in the form of a higher capacity price. On the other hand, when there is excess capacity, it would be inefficient to encourage the rapid exit of existing plant, since it offers a low cost option for the future. On the upside of the capacity target, a shallower gradient would help to moderate the fall in prices and to ensure that existing plant is not inefficiently closed prematurely.

A sloped demand curve will help to stabilise prices in the I-SEM, where an additional generator could account for a significant proportion of peak demand. Given the lumpiness of additions to supply, the I-SEM may see a saw-tooth pattern in capacity prices from one year to the next, which would increase risk for market participants and potentially deter investment. A sloped demand curve would at least moderate this variation in prices.

However, adopting a sloped demand curve could inject regulatory uncertainty and higher costs for market participants, if the SEM Committee and/or the CRM Delivery Body are continually adjusting the parameters that define it. The points that define any sloped demand curve must be set using consistent and objective terms, e.g. by using the same plant type to define both (net) CONE and the size of the acceptable variation in demand around the target level (the Capacity Requirement). The discussion of sloped demand curves on page 109 in Appendix B of the Consultation illustrates how the capacity market in GB has applied the principle of tying the capacity market to objective parameters.

We therefore support the adoption of a sloped demand curve, but only on condition that it can be defined objectively, transparently and consistently, in a stable and predictable manner, without injecting additional regulatory risk and opportunism in the market through the manipulation of the demand curve parameters.

5.9.7 Winner determination. Do you agree with winners being determined purely on price offered for each Capacity Delivery Year?

It is inefficient and discriminatory to determine winners purely on the price in their bids when they are being offered different contract lengths. Allowing new entrants to choose the length of their contracts (up to some limit) presents consumers with an asymmetric risk. In years of lower-than-average capacity market prices, new entrants will not be needed and would in any case be unlikely to accept long term contracts for any new plant. In years of higher-than-average capacity market prices, capacity is in short supply, new entrants will be in demand, and consumers will be locked in to long term contracts with new entrants at high cost.

The proposal to offer new entrants long term contracts, but to assess them only against the prices in short term offers from existing plant, is therefore bound to promote inefficient choices and to increase costs to consumers.

5.9.8 Winner determination. Do you agree that the auctioneer should be able to accept "out-of-merit" bids to manage the lumpiness problem or should only in-merit bid be accepted? What rules should be used to determine whether the marginal bidder is accepted (if only in-merit bids can be accepted) or to determine which out-of-merit bid should be accepted?

The auctioneer should only be able to accept in-merit bids, but the definition of "in-merit" must be extended to accommodate the problem of lumpiness.

The optimal approach to equating supply and demand would involve running an optimisation algorithm to maximise social welfare across all possible combinations of capacity bids, and then paying each bidder their marginal social opportunity cost (a somewhat complex concept), subject to the constraint that the bidder covered its costs. The approaches listed in the Consultation Paper involve accepting the cheapest bids up to a point just below the capacity requirement, and then seeking to plug the gap optimally with the "lumpy" bids that remain, *given that the inframarginal bids have all been accepted*. We can see that such a truncated selection method may be deemed necessary, for the purpose of transparency and to minimise costs. However, we note that the resulting solutions are bound to be less than optimal and that the RAs should therefore select the option most likely to approximate an optimal outcome, and should avoid selecting options for opportunistic or short-term gains.

A single decision instrument (price) cannot simultaneously deliver truthful bidding and commission the efficient quantity when each bid has two dimensions (quantity and price). However, some decision methods are more efficient than others and assessing their efficiency requires detailed analysis of bidding incentives.

The approach advocated in the Third Consultation Paper (paras 5.6.8 to 5.6.14) is to accept out-of-merit marginal bids on a pay-as-bid basis and to pay all in-merit bids the price of the last accepted in-merit bid (before the marginal bid). The supporting analysis does not consider the impact of this pricing rule on the bidding incentives of out-of-merit plant and makes the mistake of assuming that bids are constant across all auction formats. If a small plant with low costs (say €25/kW) can earn €36/kW by being selected out-of-merit, its owner would not bid its true costs in the auction, for fear of being counted as inframarginal and earning only €30/kW. Instead, it would bid something just under €36/kW on the chance of being accepted out-of-merit. Thus, the RA's proposal will encourage various forms of gaming (i.e. bids whose prices deviate from actual costs, leading to inefficient outcomes).

As for the rules used to select the winning marginal bid, it would be inefficient and anti-competitive to take into account its effect on the price paid to inframarginal bids (as suggested by the example given in Figure 11 for the "net consumer welfare" rule – see above). The method of selecting the marginal bid should only take account of its bid price or else its net cost – i.e. the cost of accepting a bid, less the value of any excess quantity to consumers (as defined by the sloped demand curve in the range covering the bid). The latter method is more efficient but less transparent. Both methods identify which bid is the next in merit (and also the marginal cost of meeting the capacity requirement), given the prior acceptance of the inframarginal bids. However the impact such a rule could have on security of supply in a small market like the I-SEM, with relatively large unit sizes, should be carefully considered. Given the I-SEM's relatively low security standard selected (i.e. 8hrs compared to 3hrs in GB), the risks of under-procurement, additional lost load and a consequent reduction in social welfare may typically dominate costs from slightly over-procuring capacity. Accordingly, it may be more appropriate to clear the full volume of the "marginal" bid.

5.9.9 Price determination. Do you agree that it appropriate to pay auction winners on a "pay-as-clear" basis, with this uniform clearing price being based on the highest accepted in-merit bid price? Should any out-of-merit winners be paid a different price to in-merit winners?

We agree that it is appropriate to pay auction winners on a "pay -as-clear" basis, provided the pricing rule is set correctly and provided that the auctioneer does not seek to meet the capacity requirement by accepting out-of-merit bids (see answer to 5.9.8 above).

Auctions result in efficient allocations when bidders' optimal strategy is simply to bid their own cost of providing the service. Setting prices based on the "highest accepted in-merit bid" will create incentives for marginal plant to bid more than their costs in order to influence the price if they win (see answer to 5.9.5). The analysis in the Third Consultation Paper suggesting that prices will be lower if the price is set equal to the highest accepted in-merit bid is therefore incomplete because it does not take account of how changes in the auction format will affect bidders' strategies. In principle, selecting the least-cost losing bid would come to the same (expected) price (See answer to 5.9.10 below).

Indeed, if we take the example shown in Figure 10 on page 60 of the Third Consultation Paper, the marginal cost of the capacity required to meet requirements (as defined by the sloped demand curve) is *at least* €35/kW, as defined by the price in bid 4. For some reason, paragraph 5.6.5 omits this solution as one of the possible "approaches" to setting the pay-as-clear price for in-merit plant. Given the selection of bids 1 to 3, the marginal cost – and hence the competitive price – of capacity is at least €35/kW. The cost of meeting the residual demand is either €36/kW (with bid 5) or the price of bid 4 (€35/kW) augmented by the net cost (above the sloped demand curve) of buying units 25 to 39. Approach 2, which would set the price as low as €30/kW, only succeeds by (falsely) restricting the level of demand to 24 units and by setting a different, discriminatory price for the additional marginal unit.

Although marginal bids may have to be selected via a different process from the inframarginal bids (see answer to 5.9.8 above), they should if possible receive the same clearing price as other in-merit plant to avoid discriminating without objective justification. In the example in Figure 10, it would indeed be possible to pay bid 4 its price of €35/kW, which we have defined here as the clearing price. If it were cheaper to replace bid 4 with the single unit of bid 5 at €36/kW, the auctioneer should do so (and should reverse the payment to bid 4 as if it were "constrained off").

The price paid to bid 5 in these conditions would be derived from its own bid, which may create incentives to distort bid prices (see answer to question 5.9.5 above), but that appears to be inevitable and a feature of all the schemes being considered.

(The extent of the distortion depends on the competition provided by bids 6 and higher, which are not listed in Figure 10.) Bid 5 is in-merit and might be said to define the competitive clearing-price for all accepted capacity (at €36/kW), since the cost of meeting the residual demand with bid 4 is even higher.

We can therefore see two possible approaches (neither considered in paragraph 5.6.5) which better reflect a non-discriminatory competitive market outcome. We describe them below with reference to the example in Figure 10:

A) Rank all bids by the price alone, but compare the total net cost of the last in-merit bid required to match demand (here, bid 4) with the total net cost of the remaining bids; select the least-cost remaining bid(s) that match demand (here, bid 5) and take the clearing price from the (highest) price of the bid(s) concerned (here, €36/kW); or

B) Rank all bids by their price alone and take the clearing-price for in-merit plant (here, €35/kW) from the last in-merit bid required to match demand (here, bid 4), whether it is accepted in full or rejected in favour of a smaller out-of-merit bid (here, bid 5) that has a higher price but a lower total cost. Bid 5 would earn its pay-as-bid price of €36/kW.

Approach A is equivalent to Approach 1 in paragraph 5.6.5. The clearing price depends on the method used to select the marginal bid. Approach B is less dependent upon the algorithm used to select the *actual* marginal bid, since it is based on an "unconstrained" merit order of bids based only on their price. The difference between clearing prices in Approach A (Approach 1) and Approach B is relatively small here. It is likely to be relatively small in practice if a number of bids are competing to meet demand at the margin. Each approach produces a result close to a competitive market-clearing solution, whereas Approach 2 in paragraph 5.6.5 does not clear the market and applies an unjustifiable discriminatory price rule.

After rejecting Approach 2 in paragraph 5.6.5 we can therefore envisage a number of Approaches which avoid discriminating unduly between marginal and inframarginal bids, and which produce an outcome akin to a competitive market price for capacity.

5.9.10 How do you think the lumpiness / discrete bid issue should be dealt with?

The costs of under-procuring capacity are related to VOLL and likely to be large relative to the costs of procuring additional generation. However, efficient-scale generation in the Irish market is large relative to peak demand in the market. Accordingly, the auction rules should not unduly discourage the selection of large bids, as they may be optimal. There may be larger risks to social welfare from under-procurement given the low security of supply standard and small market size, which would suggest accepting large marginal bids even if they result in over-procurement (see discussion in question 5.9.8 above).

In selecting from a number of over-sized marginal bids, it will be important to apply an algorithm that approximates the competitive, least-cost solution (such as "net social welfare") and to avoid algorithms that apply monopsonistic, least-price solutions (such as "net consumer welfare").

The presence of lumpiness is not a valid justification for discrimination, as suggested in Approach 2 in paragraph 5.6.5.

5.9.11 Do you have any comments on the treatment of tied bids?

The implementation of bid regulation may cause bids to be tied more frequently in Ireland than otherwise, or in other markets, because several generators use similar technology and have similar costs (at least in principle).

Auction clearing rules need to be transparent and must guarantee to rank bids in a unique combination so that the auction price can be quickly announced. Capacity markets therefore rely on a series of simple rules for selecting tied bids to ensure that the capacity price can be quickly identified.

In order to maximise economic efficiency, tied bids should be accepted in the combination that most closely matches the demand curve.

5.9.12 What is the appropriate level of information to be provided: before qualification; between qualification and the auction start; between rounds in the case of a multiple round auction; and after the end of auction?

Competitive auctions are more likely to produce efficient outcomes when market participants have the maximum amount of information to prepare their bids. Given the preference for a sealed-bid format expressed in the Third Consultation Paper, there is less need to conceal information from bidders to ameliorate market power concerns.

In a multiple-round auction, it may be necessary to limit the information available to bidders, for instance by not naming each of the units that remain in the auction, to prevent any suspicion of tacit coordination. It may also be necessary to limit the information about the exact supply and demand balance, to prevent exercise of unilateral market power. Limiting information however undermines the potential benefits of a descending clock auction format.

We believe that these arguments militate in favour of adopting the sealed-bid auction format. If the auction format eventually adopted has multiple rounds, we would expect further consultation (or further technical discussions in the relevant workstream) on the precise nature of the data to be released between rounds.

5.9.13 Are any additional restrictions on bidder communications (over and above existing competition law) required?

In our view, existing competition law already restricts bidder communication sufficiently.

6. CRM III Questions – Section 6

Below, we set out our response to the questions in section 6 of the Third Consultation Paper. Where appropriate, we refer back to our comments in sections 1 and 2.

6.5.2 Do you have any comments on the overall scope / process of auction parameter setting outlined above?

Auction parameters must be objectively defined to reduce regulatory risk for participants and thereby costs for consumers. Accordingly, auction parameters should be set with reference to objective data, such as public information on unit sizes or CONE calculated by a transparent and stable formula (see discussion in 5.9.6 above). In defining the demand curve, simple links to the net cost and design capacity of new entrant plant (CCGT, OCGT or other peaking plant, as appropriate) are less open to dispute and so more suitable for setting the parameters of the demand curve than formulae relying on LOLPxVOLL.

6.5.3 If a sloped demand curve is introduced, what principles should be used to determine the slope of the demand curve, and the range within which the demand curve is sloped?

See answer to 6.5.2 above. The points that define the starting, ending and inflexion points of the demand curve should be defined using; (1) a Capacity Requirement derived from technical studies carried out by the system operator in accordance with long term planning procedures intended to support security of supply; (2) public information on the unit size and costs of typical units suited to I-SEM conditions; (3) consumer valuations of lost load produced or updated annually by stable and replicable procedures.

6.5.4 If introduced, should the sloped demand curve be different for the transitional period?

It is hard to envisage any reason why the demand curve should differ between transitional (if applicable) and other years.

6.5.5 What impact do you think the sloped demand curve will have on competition?

The sloped demand curve will help to increase competition by stabilising the saw-tooth pattern of prices and somewhat reducing the scope for abuse of market power. However appropriately targeted market power mitigation measures would still be required – e.g. to protect against “below cost bidding”. Please see our answer to question 5.9.6 above.

6.5.6 Do you agree with the requirement for an Auction Price Cap? What principles should be used to determine the level for the Auction Price Cap/what level should it be set at?

An auction price cap offers an important protection for consumers against abuses of market power. However, the price cap must not be set too low or it will cause underinvestment and result in excessive costs for consumers in the form of low security of supply.

Imposing an auction price cap of 1 x Net CONE would cause inefficiency. Because of the possibility of prices falling below this level, but never rising above it, a 1x cap would guarantee that some marginal (and other) generators would fail to recover their costs, except in the unlikely event that the price of capacity clears at the cap for ever. The purpose of setting the price cap as a multiple (>1) of Net CONE is:

- to compensate for the periods when it is a fraction (<1) of Net CONE; and
- to build in a margin for the risk that Net CONE is not accurately estimated, given the asymmetric risk of setting the Net CONE parameter too low.

Market equilibration will normally ensure that expected revenues equal 1x Net CONE over the long run (although changes in Net CONE due to technical progress complicate the picture).

Investors will be wary of relying on the correct and realistic calculation of Net CONE based on experience in the SEM where the BNE calculation has employed unrealistic assumptions (relating to WACC, plant life and IMR) which have had the effect of reducing the BNE price below market levels. As Net CONE will be a key parameter in the capacity auction, it should rely on objective parameters to ensure it is not prone to regulatory manipulation and its derivation should be specific to I-SEM and must therefore:

- be based on Net CONE at the time of product delivery (e.g. for a T-4 auction in four years' time), not the current Net CONE (para 6.3.6).
- allow for the possibility of unremunerated RO rebates
- Be based on a plant life of 10 years, consistent with the maximum RO contract duration for new investments[15]

6.5.7 Do you agree with the requirement for other Bid Limits?

Bid caps (limits) should be carefully targeted on dominant players who might influence prices otherwise they will damage competition.

The purpose of adopting a capacity market, as opposed to a capacity price, is to allow the market to signal the value of capacity. A targeted approach to market power mitigation is therefore required to allow the market to function competitively. Widespread attempts to regulate individual bids will be prone to error, create inefficiency and undermine competition.

[15] It is unclear from the text how the calculation of Net CONE will allow for the difference between the plant life of the plant concerned (e.g. 20 years) and the length of contract being offered to new entrants (up to 10 years). Giving new entrants security of cost recovery would require the Net CONE to be calculated over a 10-yar plant life.

The capacity market already contains an artificial restriction, in as much as existing plant is only allowed to obtain annual contracts for capacity. Existing capacity subject to this rule cannot therefore secure a higher price when longer term shortages are anticipated, as it would in a competitive market. Accordingly, existing capacity should have flexibility in bidding, in order not to stifle competitive price signals.

Restricting bids through limits tied to operating costs and excluding sunk costs would risk preventing existing generators (which are merely the new entrants of previous years) from recovering their investment costs.

We note however that the Third Consultation Paper recognises the possibility of predatory or below cost pricing. Since this tactic would threaten competition, efficiency and security of supply, it will also be necessary to apply bid floors to any parties who might use a dominant position to depress prices (rather than to raise them). Such bid floors will not contradict guidelines on State aid, where they apply, since they will not support the auction outturn price any higher than the competitive level. Our concerns regarding predatory pricing are discussed in more detail in section 1.3 and in response to question 4.8.2.

6.5.8 Should the other Bid Limits be applied at the same level to all existing non-intermittent firm transmission access generators, or should the limits be technology specific?

We cannot envisage any system of technology-specific Bid Limits accurately reflecting all the costs of each technology, including the costs associated with unremunerated rebates and other risks. Any attempt to invoke such Bid Limits is bound to prevent total cost recovery, to hinder competition and to discourage efficient provision of capacity. Therefore, technology-specific Bid Limits seem to be out of the question.

General Bid Limits would have to be set high enough to cover the cost of the most expensive capacity, including the cost of unremunerated rebates and other risks. Such general Bid Limits would inevitably interfere with competitive bidding, hindering competition, and would most likely deny some (high cost) generators the opportunity to recover their total (efficiently incurred) costs.

Bid Limits should therefore be targeted on the dominant players who can influence prices, in order to avoid over-regulation. Moreover, such Bid Limits should include not just caps to prevent over-pricing, but also floors to prevent below-cost pricing, a risk that is acknowledged in the consultation paper.

6.5.9 Should the other Bid Limits be applicable to all bidders, or just dominant/ pivotal generators?

In order to avoid stifling competition, bid limits should be targeted at market participants who have market power. In the I-SEM, the SEMC's modelling work to date has demonstrated that only ESB will have significant market power. Accordingly, bid limits should only apply to ESB.

Given ESB's state ownership and potentially non-commercial objectives, bid limits should be symmetric, ensuring ESB neither bids too low or too high.

6.5.10 What principles should be used to determine the level for the other Bid Limits/what level should they be set at?

See our answer to question 6.5.8. Bid Limits should be appropriately targeted on dominant CRM participants, in order to avoid over-regulation.

7. CRM III Questions – Section 7

Below, we set out our response to the questions in section 7 of the Third Consultation Paper. Where appropriate, we refer back to our comments in sections 1 and 2.

As a general but important point, it should be clarified how the RAs intend to develop the Capacity Market Code, who will be given responsibility for this and its legal drafting, how will industry be involved in the process of rules development and what mitigation measures will be implemented to manage conflicts of interest if the TSOs are given responsibility for developing the rules and / or legal drafting.

A) Do you agree on the proposed role of the TSOs with respect to the auctions?

The Consultation Paper allocates a wide-ranging role to the TSO as the capacity remuneration mechanism delivery body, including running the prequalification process, developing the auction guidelines, approving key auction parameters and running the auction itself. Some of these roles may allow EirGrid to affect the auction outcomes significantly. Where possible, decisions on substance, such as the auction parameters, should be taken out of the hands of the TSOs and should reside with the SEM Committee so that the TSOs' role is only to administer the auction.

As stated in the Consultation Paper,[16] EirGrid and SONI are shareholders in interconnectors which will participate in the auction. That creates a perceived conflict of interest with administering the auction. For instance, EirGrid and SONI may have discretion over the methodology used to de-rate capacity, including interconnectors participating in the auction. The solution to this conflict of interest is to ensure that the TSOs have no control over parameters and processes which would favour interconnectors. In Great Britain, faced with a similar problem, DECC commissioned independent consultants to determine the de-rating methodology for interconnectors. Conditions in the I-SEM demand a similar approach to that adopted in Great Britain.

The SEM Committee should clearly set out its reasoning on whether the TSOs have a conflict of interest for each of their roles and its strategy for managing that conflict. If the TSOs retain any role in decision-making, it must be subject to independent scrutiny and detailed review by the independent auction monitor. That independent review should focus particularly on those areas most likely to favour or disadvantage interconnector participation.

B) Do you agree on the requirement for an Independent Auction Monitor and its proposed roles and responsibilities? If not, please specify what changes you would make? Should this role be combined with the role of SEM/I-SEM Market Auditor?

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[16] Consultation Paper, para 7.8.1.

We agree that the auction process will require an Independent Auction Monitor. The scope of its role proposed by the RAs is, however, unduly limited. The Consultation Paper suggests that the role of the market monitor would be to "assist the RAs in monitoring that the CRM Delivery Body and market participants have complied with the Capacity Market Code".[17] This scope suggests that the duty of the independent market monitor would be to support the RAs' activities.

In practice, given the dominance of a single, state-owned entity in the Irish market, it will be important that the Independent Auction Monitor provides a truly independent view of the operation of the auction. In order to execute this task, the Independent Auction Monitor should meet the following conditions:

- Have a clearly-defined remit for investigating abuses, encompassing the full range of potential abusive behaviour in the auction. That remit should include an obligation to investigate both exploitative conduct to increase prices and predatory conduct aimed at reducing prices.
- Have a clear and transparent duty to investigate the TSOs' conduct in running the auction process and in particular on its management of conflicts of interest.
- Have a positive duty to report publicly its findings on the conduct of market participants and the RAs. The Independent Auction Monitor should not be restricted to reacting to concerns expressed by the RAs or market participants.
- Be well enough resourced to carry out its task, including access to all of the information necessary to assess the auction outcome.
- Be an expert and independent third party with previous experience of analysing competition economics in electricity markets and capacity markets. The staff acting as auction monitor will also need to have experience of the particular characteristics of the Irish electricity market in order to apply their understanding of competition enforcement appropriately.

The SEM Committee should procure monitoring services transparently, setting out clearly the criteria by which market and capacity market monitors will be selected (see also a discussion of the criteria that might be used, in question F below). Whether the auction monitor role should be combined with the market monitor for the I-SEM will depend on the characteristics of those offering to take on the role of auction and market monitor received by the SEM Committee.

The two roles will draw upon a common skillset, an understanding in particular of the Irish market and more generally of competition economics in electricity markets. However, the auction and market monitor roles are separable, in principle. The auction auditor will also need to have some knowledge of international experience in applying competition economics to capacity markets. The SEM-Committee should not rely on the I-SEM market monitor to monitor the capacity auction unless he or she has the requisite experience of international capacity markets.

[17] Consultation Paper, para 7.6.1.

C) Do you agree with the SEM Committee's proposed approach to managing conflicts of interests in the Capacity Market Code? Are any other steps appropriate to ensure that any actual or perceived conflicts of interest are managed?

The SEM Committee's proposals set out the range of measures we anticipate being necessary to manage the TSOs' conflicts of interest (ring-fencing, behavioural measures, control/oversight and transparency).

Throughout the auction process it will be necessary to ensure that the auction delivery body operates at arms-length from the TSOs' general management. The objectives and code of conduct of the auction delivery body must be clearly and transparently defined. The auction monitor and the SEM Committee must hold the auction delivery body to account against both these stated objectives and the code of conduct (see answer to question C, above).

D) Do you have any comments on the proposed auction governance arrangements?

The Consultation Paper proposes that the Capacity Market Code will contain the detailed rules and that the Auction Agreed Procedures will be confined to the practical matters necessary to operate the auction. The governance process allows for modifications to the Capacity Market Code but does not allow for consultation on the Agreed Procedures.

Given the lack of any provision for consultation on the Agreed Procedures, it is important that the SEM Committee has a clear and transparent approach to ensuring that the Agreed Procedures are in practice confined to processes and do not stray into decision-making. Moreover, the Capacity Market Code should ensure that market participants have an opportunity to object not only on procedural matters but also to rules in the Agreed Procedures, or proposed rules, that they identify as problematic, such as the choice of important parameters that should instead feature as part of the Capacity Market Code.

E) Do you have any views on the model and process for making modifications to the Capacity Market Code?

Modifications to the Capacity Market Code should follow a transparent process, with full information provided to all market participants throughout. It is particularly important to provide full information to capacity market participants due to the short timeframes over which code modifications may have to occur between auctions.

The proposed process for modifying the Capacity Market Code does not clearly specify the format of the required consultation on proposed modifications. The modification process should commit the SEM Committee to provide its detailed reasoning behind any decision, including its reasons for rejecting alternative proposals, to ensure robust decision-making. Such a commitment would help to bring this area of the SEM Committee's remit into line with best regulatory practice.

F) Do you think that disputes in respect of the Capacity Market Code should be resolved by a similar process to TSC disputes? Should there be a separate panel for Capacity Market Code dispute resolution?

The SEM-Committee should apply clear and consistent criteria when deciding what institutions would be necessary under the I-SEM and publish its evaluation under those criteria. Such criteria could include:

(1) whether there is a need for a specialist panel that can acquire a detailed knowledge of its task, for instance because disputes under the Capacity Market Code are likely to be frequent;

(2) what mix of skills the panel would require and whether the existing panels used for TSC disputes would be able to resolve disputes satisfactorily; and

(3) whether the TSC or another panel would benefit from the additional experience that would come from resolving disputes under a variety of codes.

8. CRM III Questions – Section 8

The SEM Committee has requested views on all aspects of this section of the Third Consultation Paper, including detailed questions A to F. Before addressing those questions, we refer back to the discussion of the RO Strike Price in section 1.2 above, on minimising risk.

There, we explained why a high RO strike price is necessary to minimise the effect of "scheduling risk". We stated that the RO strike price must be set at least as high (and possibly higher) than the costs of the highest priced generation capacity operating during a system stress event. We furthermore observed that such generation capacity may not correspond to the "Best New Entrant", or even a peaker unit, but rather could be a CCGT that needs to recover its total costs over a limited time horizon, including charges for gas capacity (or the cost of delivering other fuels), start-up costs and the cost of part-loading (if for technical reasons the generator has to start before, and continue running after, the period of system stress).

We also explained that the same desire to avoid unnecessary risk requires governance of the RO Strike Price (and several other matters) to be made as stable and predictable as possible, by using objective formulae and publicly available data.

These comments provide the guiding principles behind each of the following answers.

A) Do you agree with the proposed approach to incorporating the carbon price into the Strike Price formula?

We are in broad agreement with the suggested approach to including the costs of carbon in the strike price formula but we have other concerns.

As we have explained above, it is important that the RO strike price demonstrably lies above the cost of running any existing capacity to meet demand in periods of system stress, however short-lived those stress periods may be. This cost can be quite high, since it may require recovery of start-up costs over short time periods and the cost of part-loading (i.e. running at a loss) before and after the period of system stress.

We also note that the formula omits a number of important costs of running to meet demand at times of system stress. For example, it should be amended to include O&M costs, start-up costs and the cost of procuring gas capacity. For some technologies, O&M costs are effectively a recurrent cost, because plant has a limited life between services or major refurbishments. Each hour of operation uses up some of that life and consumes the capital embodied with the plant.

The formula must therefore be adjusted to account for these costs, preferably on an explicit basis or by a proxy, e.g. adopting a thermal efficiency that is low enough to account for these costs as well as the cost of fuel and other consumables. (The former method is more transparent and hence more likely to be stable.)

B) Do you agree with the approach of moving to a month-ahead index?

No. The RO Strike Price should be updated daily, as discussed in paragraph 8.2.9 of the Third Consultation Paper. The arguments in paragraph 8.2.10 in favour of using a monthly gas price index are incomplete, because they review short term incentives but do not consider long term risks.

Using a monthly index unnecessarily increases "scheduling risk", because within a month the fuel price which dictates the short run marginal cost of a generator may rise above the level used to set the RO Strike Price at the start of the month (as proposed in paragraph 8.1.12).

As described in paragraph 8.2.10, the Administered Scarcity Price does provide an incentive to generate at times of system stress. Leaving aside the risk of outages, generators however will not recover their costs in this situation unless the RO Strike Price is set high enough to allow them to recover their variable costs of running to meet demand at times of system stress If the RO Strike Price is set below this level, generators will lose money each time there is a period of system stress. The auction price for ROs might offer some compensation in expectation, but the hedge is imperfect, and Bid Limits (or auction price caps) would undermine the opportunity for generators to cover their costs by this method. In any case, it is undesirable to rely on "incentive incompatible" schemes that offer adverse incentives in the short term.

Monthly indexes by definition do not represent the day to day volatility of spot prices. If the RO strike price were therefore defined with reference to monthly indexes, it would not reflect the actual day to day running costs of generators. Consequently generators would then have to make larger rebates under the RO, without earning any offsetting revenue from sales of energy, which would be capped at the strike price. The risk of this situation occurring will unnecessarily drive up the price that these generators have to bid for capacity (imposing unnecessary commercial risk onto generators, undermining total cost recovery and reducing the efficiency of the capacity auction outcome).

Thus, considerations of risk minimisation and efficiency in the capacity market, rather than short term incentives, require that the RO strike price is indexed daily, so that it remains above the marginal cost of generation at all times.

C) Do you agree that a reference thermal efficiency of around 15% is appropriate? If not, why not?

The formula set out in paragraph 8.2.1 and amended for carbon pricing in paragraph 8.2.5 makes no provision for costs other than fuel and carbon. The short run marginal cost of running a generator include a number of other costs, including, but not limited to, gas capacity costs, start costs, O&M costs, etc. It is therefore not clear that the thermal efficiency of 15% is sufficient to cover all of these costs.

Furthermore, it is essential that the RO Strike Price resulting from the formula should be high enough to cover not only the costs of the technology assumed in the formula, but also the running costs of every other form of capacity in the I-SEM, including

CCGTs bidding gas capacity costs and recovering start costs over short time horizons. If the RO Strike Price lies below the running costs of any single generator, that generator will be losing money at times of system stress, giving it a perverse incentive to avoid such commitments, by avoiding ROs or selling them to others (if that is at all possible). The RO Strike Price therefore needs to be set with the objective of avoiding such cases for all existing capacity (not just of reflecting the cost of a particular type of capacity).

We appreciate that setting a particularly low thermal efficiency can compensate numerically for the omission of other costs. However, such approaches lack transparency, so the adjusted efficiency is open to criticism for being inaccurate, and the formula is vulnerable to arbitrary adjustments if it starts out with only a tenuous link to objective, publicly available data. Therefore, whilst any adjustment for the extra costs is better than none, we would strongly prefer a formula for the RO Strike Price that makes these adjustments explicit.

D) Do you agree that the appropriate oil price is the Heavy Fuel Oil price?

No. The formula should use the maximum of the various possibilities (as in paragraph 8.2.5), to ensure that the strike price is set at least as high (and possibly higher) than the costs of the highest priced generation capacity operating during a system stress event. This will help to avoid the issues outlined in our answers to previous questions in this section.

E) Do you agree with the principles / criteria set out in Section 8.2.28, that the SEM Committee proposes to use to choose between data sources for fuel and carbon prices, exchange rates?

The criteria set out in paragraph 8.2.28 are the right ones, subject to the following comment. It is hard objectively to define levels of liquidity, or to say whether or not a reference price is a "robust representation of market prices". The RAs should therefore check mainly that the index closely reflects the price at which a generator might actually buy fuel ("expect to achieve through trading in the physical market"). In the course of this investigation, the RAs should not rely solely on the views of the CRM Delivery Body, but should also seek expert input from companies actually involved in trading, as well as independent third party consultancies with relevant expertise.

F) Do you agree with the proposed governance / process for changes to fuel and carbon prices, exchange rates and transport adders used in the calculation of the Strike Price?

There are many reasons why the RO Strike Price formula should be as stable as possible. For instance, we expect that the rebates made under other CFD forward contracts will have to be adjusted by the RO Strike Price so that they do not overlap with rebates made under ROs. (Otherwise, CFDs will not properly hedge market price risks.[18]) Because of the interaction between ROs and settlement of CFDs, the SEM Committee will have to exercise extreme caution when authorising any changes to the formula of the RO Strike Price. Any changes that render existing CFDs ambiguous or non-performable will have major implications and costs for the industry.

Equally, if the current formula for the RO Strike Price proves to be problematic or non-performable (e.g. because a parameter proves to be inaccurate or a particular price index ceases to be published), the SEM Committee may have to order the CRM Delivery Body to review and possibly to change the formula in time, and in a manner, that ensures the continued ability of the market to conclude, trade and settle CFD forward contracts.

To meet these needs, it would be advisable to instruct the CRM Delivery Body to maintain the formula according to certain principles (rather than having the SEM Committee order revisions from time to time, which may appear to the market as arbitrary and as a source of regulatory risk). These principles would be drafted as the duty of the CRM Delivery Body to maintain a formula that:

- Ensures the RO Strike Price lies above the total cost of operating any generator that is registered within the I-SEM, including over a very short time period, or that would be economically viable in the I-SEM, given the expected frequency of system stress periods; and

- Permits at all times the conclusion, trading and settlement of other contracts referring to the RO Strike Price.

In applying this procedure, the CRM Delivery Body should not be the only party allowed to initiate a review of the formula or to propose amendments. There should be governance provisions that allow for market participants and the SEM Committee to trigger a review by the CRM Delivery Body. These reviews should allow for the usual level of consultation, and the CRM Delivery Body should be obliged to reflect any views submitted by others, or else to explain why it has taken a different view.

[18] This is a problem specific to the form of CRM adopted for the I-SEM, namely a one-way CFD referenced to the energy market. Capacity markets which are entirely separate from the energy market, as in the US and the UK, do not provide overlapping cover with energy contracts.

9. CRM III Questions – Section 8.3

Section 8.3 of the Third Consultation Paper includes a discussion of Difference Payments Socialisation Arrangements and asks specific questions A and B relating to this. Before addressing those questions, we would first like to express our concern that the ETA Rules Working Group is currently engaged in progressing the implementation of the socialisation fund via the market rules working group prior to the completion of the consultation process on CRM3 and any formal decision taken by the SEM Committee. The ETA Rules Working Group ought to be guided by the views put forward as part of this consultation process and the subsequent decision of the SEM Committee to ensure that due process is being followed.

The need for a socialisation fund is indicative of a flaw in the design of the CRM (a balance of payments issue), and it is therefore important that the design of a remedy does not result in unnecessary and unmanageable commercial risks being passed through to suppliers, as this would further increase inefficiency. Furthermore, to improve efficiency, the implementation of the socialisation fund must ensure that appropriate incentives are imposed upon those responsible for managing the fund – i.e. the party, or parties, responsible for determining its value and the rate of contributions. These objectives can only be achieved if: 1) the cost of the fund can easily be recovered by suppliers from the final energy user / customer; and 2) the cost of managing the cash flow risk associated with the fund is borne by EirGrid / SEMO.

A) Do you agree with the proposed approach for setting the Supplier's contribution rate? If not, please explain.

Energia would welcome clarity of the estimated size of the "hole in the hedge". The principles espoused in 8.3.7 and 8.3.8, particularly those relating to "avoiding shocks", which impose potentially arbitrary restrictions on changes to the contribution rate, are only reasonable if the cost of managing the cash flow risk associated with the fund is borne by EirGrid / SEMO. This ensures that there are appropriate incentives on EirGrid / SEMO to accurately determine the value of the fund required to deliver a 90% confidence interval, as well as set an appropriate contribution rate.

In relation to the "Pragmatic" principle, Energia believes it would be beneficial to set out the principles that will guide the SEM Committee's decision making when choosing between competing objectives. This would greatly help to bring a degree of objectivity to the process and remove any potential perceptions of regulatory risk.

Energia furthermore recommends that consideration is given to including a reasonable levy, on a per MWh basis, to the CPDP (Capacity Period Demand Price) for October 2016 to September 2017. This would allow the build-up of the fund to commence prior to the start of the I-SEM therefore helping to relieve any potential working capital burden on EirGrid / SEMO.

B) Do you have a preference as to which option (Suspend and Accrue or Immediate Additional Charge) should be applied to socialisation of any shortfall in Reliability Option difference payments? If not, please explain.

Energia does not support either option put forward in the consultation paper. Both options expose suppliers to unnecessary and unmanageable commercial risk, and will increase inefficiency by removing appropriate incentives from the party, or parties, responsible for managing the socialisation fund. Both options transfer the working capital obligations from EirGrid / SEMO onto suppliers, despite the fact that EirGrid / SEMO are likely to have lower costs of capital, and in so doing could impose substantial and potentially volatile costs on suppliers that would be difficult to forecast and efficiently recover through retail tariffs[19].

The cost of managing the cash flow risk associated with the socialisation fund must therefore be borne by EirGrid / SEMO – i.e. the parties responsible for setting the value of the fund and the contribution rate. As previously stated, this will ensure appropriate incentives are in place for the efficient operation of the fund. Furthermore, it allows any surplus or deficit in the fund to be managed by means of a K-factor, similar to other charges, such as Imperfections.

[19] Ultimately customers will bear a higher cost because of the inefficiency of the proposed arrangements.