Power NI Energy Limited
Power Procurement Business (PPB)

I-SEM Detailed Design

Capacity Remuneration Mechanism

Second Consultation Paper

Response by Power NI Energy (PPB)

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Power Procurement Business

Introduction

PPB welcomes the opportunity to respond to the RAs second consultation on the detailed design of the Capacity Remuneration Mechanism.

General Comments

The CRM is a critical element of the I-SEM that is essential to ensuring the long term stability and security of supply in a small island market. Reliability Options (ROs) are relatively complex instruments that incorporate both a hedge against high spot market prices and scope to recover money that is missing more generally from the energy market. Their operation is further complicated in the context of a small system that is targeting high levels of intermittent generation.

The following summarises PPB's views on the issues raised in the second CRM detailed design consultation.

Interconnector and Cross Border participation

Facilitating cross-border participation in CRMs in not easy and is a challenge that is being considered across Europe. The issue is bound in with the more generic consideration of generation adequacy assessment by TSOs in neighbouring jurisdictions and it requires strong assurance that contractual arrangements will be honoured to maintain cross-border flows when disconnecting customers in the exporting region if the capacity is to be relied upon as firm.

A key principle must be that all capacity that is being secured to provide security of supply for customers in the I-SEM must fulfil the same requirements and be exposed to the same rights, obligations, payments and penalties for non-performance as indigenous capacity.

The only viable approach is therefore to ensure participants are assessed on their actual performance in providing MW when customers require them. The "Availability Based" variants for cross-border participation would provide preferential treatment relative to the obligations imposed on indigenous I-SEM capacity providers to actually deliver electricity and are therefore not viable options.

None of the options are perfect but we consider the Provider Led approach to be the most equitable and will ensure non-discrimination between indigenous and cross-border capacity.

De-rating is an important consideration and must reflect the reliance that I-SEM customers can place on capacity being delivered to secure security of supply. This is not an easy assessment to make and there are many factors that will affect the delivery. Given this requires co-ordination across member states, it would clearly need to take a prudent and conservative approach while confidence is built that capacity contracted under a CRM can and will be delivered when required. Historic interconnector flows between GB and the SEM have been distorted by the market arrangements and will likely be very different once market coupling is established. GB also has an increasing capacity deficit and the prevailing flows are likely to be exports to GB, in which case the interconnectors are providing virtually no contribution to security of supply in the I-SEM market.

A key concern in relation to interconnector de-rating is Eirgrid's conflict of interest as owner of EWIC. It is imperative that an independent entity is charged with developing the de-rating methodology for interconnectors.

Secondary trading

Generators will have outages and a liquid secondary market is essential for smaller participants to enable them to manage their RO exposures during such outages. If a liquid secondary RO market is not established, the only alternative risk management option would be for small participants to increase the risk premium in their CRM bids. This has a number of negative consequences as it could mean smaller participants are less successful in the CRM auctions, exacerbating dominance in the markets, or even if successful in the CRM auction, the risk remains that the uplift does not fully reflect the cost for the participant and the cost for customers will likely be higher.

The liquidity of the secondary RO market and potential for market power are major issues that must be addressed to provide participants with effective risk management tools. The primary issue is that the market is relatively small while ESB will likely hold a dominant share of ROs for the foreseeable future and as a result will have the majority of "spare" capacity in excess of de-rated capacity that would be capable of providing liquidity in the secondary market. Therefore any large generator seeking to manage its RO exposure during an outage will likely to have to trade with ESB. However, ESB's incentive to trade in the secondary market is unclear given they have the ability to self-hedge across their own portfolio and hence we consider liquidity promoting obligations will be required for ESB.

We consider the Mandatory Centralised Market option represents the best approach to concentrate liquidity and to ensure transparency in what will be a relatively thin market and that a trading platform is required before I-SEM go-live to enable participants with planned outages to trade out their RO exposures as soon as possible.

Detailed RO Design issues

RO Contract Length

PPB fundamentally disagrees with the proposal that only new entrants and re-furbished plants have access to longer term contracts and we consider that the same contract terms should be made available to all participants. There is nothing presented in the consultation paper to justify unfairly discriminating against existing providers where they can offer the MW required for whatever duration is required.

We believe that favouring new or refurbished capacity in this way is not consistent with the requirement to promote competition. In this regard, we note that while the EC provided State Aid clearance of the GB capacity mechanism that makes provision for longer term contracts for new entrants, this has been challenged on the basis of its discrimination against existing capacity which reflects our concern with the current I-SEM CRM proposals.

The somewhat unusual approach taken in Great Britain, offering “up to” 15 year contracts, offers no useful precedent for the I-SEM and for reasons of administrative simplicity and non-discrimination, we favour an approach that offers annual contracts to all generators, bolstered by the promise of stable revenues in subsequent annual auctions.

If new entrants must be offered a better deal than existing plants, then we consider the examples of the 3-7 year contracts in other markets provide the best indication of what is required and appropriate, with a preference for the shortest possible duration.

Stop Loss Limits

A liquid secondary RO market and Stop Loss limits will provide risk management tools for participants to manage the risks associated with ROs. Pricing in the Balancing Market is still being considered, the implementation of Administered Scarcity pricing remains uncertain, scheduling risk remains a concern, and market power mitigation measures remain undefined. This means there remain substantial risks for capacity providers that will not be alleviated until the I-SEM has been operating for a number of years. We therefore consider that the annual Stop Loss Limit should be set such that the potential loss under an RO contract cannot be more than the revenue received.

This provides a meaningful risk mitigation measure for capacity providers while still providing significant incentives on RO holders to be available since any loss means they would not be capturing the “missing money” that they require under the CRM.

Administered Scarcity Pricing creates a high risk to shorter term cashflows and hence monthly and daily limits will assist participants in the management of this risk.

<u>Commissioning Window and Implementation Agreements</u>

A key objective of the process must be to ensure, to the maximum extent possible, the capability of potential participants to deliver should they be successful in the RO auctions. If this is not properly managed then there is a risk to security of supply, not just as a consequence of the capacity not being delivered (which may not be as great a risk in the I-SEM because new entry in more likely to be displacing existing capacity compared to GB where new entry is required to meet a capacity deficit) but perhaps more likely because of the depression in the CRM clearing price that will affect all other capacity providers in the I-SEM. In such an event, the pricing must be recalculated to exclude the phantom capacity to determine the clearing price that should have been determined had the plant not participated in the original auction.

Administered Scarcity pricing

Administered Scarcity Prices (ASP) create the primary incentive for capacity providers to perform under the ROs. The detailed design of pricing in the Balancing Market remains under discussion and the operation of ASP with the BM requires further consideration once the BM pricing arrangements are decided. Consideration of the TSOs’ operation of the system will also be required to ensure ASP are driven by market fundamentals and not by TSO actions.

ASP will introduce the potential for significantly higher prices than exist in the SEM. This magnifies the risk for participants who therefore need to be able to rely on liquid risk management opportunities to enable them to manage this risk This requires an effective forward market, sufficient flexibility of order types in the DAM, a fully functioning IDM, a liquid secondary RO market and appropriate Stop Loss limits on the ROs, all coupled with effective market power mitigation measures in all of these markets. There is also a requirement to define exceptions where the RO is not a binding obligation to ensure participants are not exposed to unmanageable risks arising from TSO actions/inactions, e.g. where the unit is available and participating in the BM but for whatever reason is not dispatched by the TSOs.

In the absence of these risk management tools, generators would be heavily exposed which could result in insolvency and disorderly exit or higher risk premiums being required in the RO auction, or both.

In terms of the level of FASP, there is a high risk of distorting cross-border energy flows if the price caps in adjacent markets are different and hence it would be rational for the objective to be to align the level of FASP with GB. However, as noted above, this creates high risks for participants if they cannot adequately manage the price risk and hence we support a transitionary arrangement that will allow experience of the operation of the I-SEM to be gained and to ensure all the required risk management tools are effective. We suggest the initial level of FASP should be aligned with the Euphemia price cap which will ensure the least impact on trading dynamics across the DAM, IDM and BM.

Transitional issues

The Do-nothing option is not viable and we support the RAs investigating the “Glide-path” option that was initially discussed at the workshop in September 2015 which we consider would be a rational transitional approach given the extent of the overall change in the I-SEM. If this is rejected by the EU then our preference is Annual auctions.

Responses to the Specific Questions

Chapter 2. <u>Interconnector and Cross Border questions</u>

The primary principle must be that all capacity that is being secured to provide security of supply for customers in the I-SEM must be capable of actually delivering the capacity when it is required. The product being secured is MW of capacity and all providers must be treated equally with the same obligations, payments and penalties.

On the basis of this criteria, all capacity must be judged on its performance when capacity is required to maintain supplies for customers. As a consequence we believe the "Availability Based" variants are not viable options and must be excluded from the list of possible options. Under such an arrangement interconnector owners or non-I-SEM capacity providers would earn RO revenues by just being available, regardless of whether or not MW were actually being deliver into the I-SEM. This represents preferential treatment relative to indigenous I-SEM capacity providers who would be exposed under their RO if they did not perform and deliver.

Q2A: Which of the approaches to the treatment of cross border capacity do you prefer and why? (For the Provider Led and Interconnector Led approach, please specify whether you prefer the "Performance based" or "Availability Based" variant).

We do not consider the "Net Off Demand" approach to be workable. It will be difficult to predict whether the interconnectors will be importing or exporting at times of capacity shortage and hence there is a real possibility that the interconnectors would not be contributing to security of supply as expected or would indeed be reducing security of supply by exporting capacity out of the I-SEM, creating higher risks for customers. We agree that it would be perverse to ask I-SEM customers to fund capacity that is being used to export and that where the assessment is a net import, that contributes to a greater hole-in-the-hedge cost for I-SEM consumers.

We do not consider that an Interconnector Led approach provides any surety of capacity since there is no guarantee that MW will be delivered when it is needed. The interconnector is largely just another transmission line and the owners cannot guarantee energy flows. In addition, the interconnectors are unlikely to be receiving high energy price payments to fund the RO difference payments and that is likely to represent a significant financial exposure. We note that GB has adopted an Interconnector led approach. However, the GB capacity mechanism does not involve ROs and the penalty for not providing capacity when required is limited to 1/24th of the annual capacity revenue for each hour of non-delivery, capped at 100% of the annual payment. This does not impose any different arrangement on the interconnector than is required of a generator and hence they are effectively treated the same in GB. Because of these differences the GB arrangement does not assist or provide any precedent for the I-SEM.

The FTR led approach does not readily align with scarcity events given the FTRs only apply to DAM trades, yet scarcity will be most evident in the Balancing Market. While the approach may address the issue for interconnectors since there will be a revenue stream to the FTR holder who is therefore in a slightly better financial position than the interconnector, the FTR payments are based on the relative price differential between the GB and I-SEM markets which may be much less that the RO payment obligation. This may not be an issue if the FTR holder is a generator in GB but additional risks remain under this option. We do not believe limiting the obligations to the DA stage is viable as it does imply an availability based approach for the IDM and BM which as we highlighted in the introduction to this section would be discriminatory.

The performance based Provider Led approach appears to provide the most equity with indigenous capacity providers. The key issue is how to ensure committed capacity is made available for supply to the I-SEM and while an audit trail should be relatively easy for the DAM, it is less obvious how to monitor such performance in the IDM. The BM provides a further challenge given there is no coupling of the markets (at least initially) and the TSO-TSO arrangements are unclear. In addition, we do not understand why zonal pricing has been introduced which creates a further distortion in the market.

Finally we do not see any value in the hybrid approach which proposes insulating external providers from outages on the interconnector. This provides a preferential arrangement compared to indigenous generators and is therefore discriminatory.

On balance our preference would be for the option that treats external capacity in exactly the same manner as indigenous capacity and we consider the Performance based, Provider Led approach to be the most equitable.

Q2B: Should the de-rating of interconnectors be based on historic performance, or include forward modelling to project how its performance could change in the future?

The 'historic performance' of interconnector flows has no relevance to future flows and the potential to deliver firm capacity when required to maintain supplies to customers in the I-SEM.

Interconnector flows in the SEM have been distorted by the advantageous trading arrangements that mean flows have occurred into Ireland when the underlying energy prices should have resulted in exports to GB. The design of the SEM also enables physical flows to be scheduled on the interconnectors by an interconnector capacity holder using electricity they have purchased at a fixed price electricity in GB which they export to Ireland to underpin a retail position. Thereafter the capability and incentive to actively re-trade the power has been limited, not least because the SEM price isn't known until after the flow has happened. As a result trading in the SEM is relatively static, bar the SO-SO trading, although we believe this has mainly been utilised to manage constraints and curtailment. The introduction of market coupling is likely to result in very different interconnector utilisation and hence historic flows provide no useful indication of future flows.

The indications are that the capacity margin in GB is getting tighter as coal plants are closing early and as a consequence of delays in the nuclear replacement programme. Similarly, GB prices are increasing as a result of the carbon price floor and therefore we expect post I-SEM interconnector flows to primarily be exports from the I-SEM to GB, opposite to the historic flows.

The price differential between the I-SEM and GB will be a major determinant and the recent proposal to impose SRMC bidding rules in I-SEM would likely create a further distortion to interconnector flows, increasing exports to GB.

Given these changes, it is essential that consideration of the de-rating of interconnectors is informed by detailed scenario based modelling of forecast conditions to enable appropriate de-rating factors for them to be determined. Clearly if the predominant flow is exports at times of system stress, then that means there is no value to be allocated to interconnectors and indeed the risk of this needs to be carefully considered. Even if the analysis indicates potential imports, this will need to be heavily discounted given the many factors that influence forecasting and the unpredictable nature of energy markets that could see a major swing in flows at short notice. Hence a large degree of prudence will need to be applied to provide adequate assurance of security of supply for I-SEM customers.

A key concern in relation to any consideration of Interconnector de-rating is the conflict of interest of Eirgrid. The first CRM Decision paper indicated that the TSOs would be tasked with developing the detailed methodology for setting the de-rating factor. We consider it wholly inappropriate for EirGrid, given its ownership of EWIC (and ambitions on further interconnection), to develop a methodology for setting de-rating factors applicable to the interconnectors as a consequence of this conflict. This is a concern regardless of the approach adopted for cross-border capacity in the CRM and therefore the RAs must engage an independent party to develop the de-rating methodology for interconnectors.

Q2C: If there is a preference for the "Interconnector led performance based" approach there will be a need to allocate total interconnector flows between specific interconnectors. Which of the specific approaches set out in 2.4.6 do you prefer? These approaches were:

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

As noted in response to Question 2A, an Interconnector led approach provides no assurance of contribution to security of supply at times of scarcity and hence is worthless for customers.

If an Interconnector led approach were adopted, the most suitable allocation approach will likely depend on the decision as to how I/Cs trade in the markets. If they trade as separate interconnectors with different loss factors, etc, then they should be treated in the same manner in the CRM and hence each interconnector would stand alone.

Q2D: If there is a preference for the "FTR led" approach, which of the specific approaches set out in 2.4.15 (net or gross) do you prefer for the allocation of non-day-ahead flows?

As noted in response to Question 2A, an FTR led approach appears impractical.

Q2E: If there is a preference for the "Performance based Provider Led" approach, which of the specific approaches set out in 2.4.25 do you prefer for the allocation of intra-day and balancing market trades?

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

As noted in response to Question 2A, the Provider Led approach appears to be the most equitable option.

In terms of allocation the key requirement would be that the external provider makes their capacity available to the DAM, IDM and BM to ensure the I-SEM can access it. Hence such capacity could not sell its output physically forward in the GB market and the DAM must be the first physical market that the capacity is made available to. Providing this audit trail can be established, then a pro-rating of the actual energy flows is likely to be the most appropriate approach. We are not clear on how the gross/net approaches would work in practice and further analysis of these would be required before we could indicate a preference.

Q2F: If there is a preference for the "Hybrid" approach:

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

As noted in response to Question 2A, we do not see any value in the Hybrid Led approach. If it were to be adopted, it would need to be "Delivery based" to minimise any discrimination against indigenous capacity providers. Similarly, any interconnector participation should be voluntary but any such participation would need to impose the same obligations on performance as applies to all other capacity providers who secure an RO.

Chapter 3. ***Secondary Trading questions***

Reliability Options imposes significant commercial risks on participants and all providers will have planned and forced outages during which they will be exposed to making payments under the RO when they have no revenues. These risks are magnified by the proposals in relation to administered scarcity pricing and a liquid secondary market in ROs is therefore essential to ensure participants have tools to enable management of these risks. This is especially important for non-portfolio participants who are exposed to a much greater extent than ESB who may have sufficient spare capacity, represented by the aggregate difference between the de-rated and maximum capacity for each of its units in its portfolio, to offset an outage on any one of its units.

A liquid secondary market is therefore essential for smaller participants to enable them to compete on a level playing field with participants with large portfolios such as ESB. If a liquid secondary market is not established, the only alternative risk management option would be for small participants to increase the risk premium in their CRM bids. This has a number of negative consequences as it could mean smaller participants are less successful in the CRM auctions, exacerbating dominance in the markets. Even if successful in the CRM auction, the risk remains that the uplift does not fully reflect the cost for the participant and the cost for customers will likely be higher. Further, such risks are also likely to be reflected by potential investors again potentially locking in a premium if they were to be awarded a long term contract or alternatively delaying efficient investment.

The liquidity of the RO secondary market and potential for market power are major issues that must be addressed to provide participants with effective risk management tools. The primary issue is that the market is relatively small while ESB will hold a dominant share of ROs for the foreseeable future and as a result will have the majority of “spare” capacity in excess of de-rated capacity that would be capable of providing liquidity in the secondary market. Therefore any large generator seeking to manage its RO exposure during an outage will likely to have to trade with ESB. However, ESB’s incentive to trade in the secondary market is unclear given they are likely to largely self-hedge across their own portfolio.

This asymmetry creates a major issue for the effective functioning of the CRM that, if not addressed, risks perpetuating ESB’s dominance in the market. These issues of market power and liquidity require early consideration to ensure a viable CRM is designed and established.

Q3A: Do respondents agree that direct secondary trading of Reliability Options should be permitted?

As already highlighted in the introduction to this section, a direct secondary market is essential to enable participants to manage their risks. Given the market is small, the arrangements must be simple such that liquidity is concentrated and that the market is easily accessible to all participants.

Q3B: Should secondary trading of Reliability Options be via an organised secondary platform? If so, which one of the options is preferred?

As noted in the introduction to this section, any secondary market for reliability is likely to be thin. We also highlighted our concerns that participants such as ESB who have large portfolios have an implicit hedge that means, in the absence of measures to promote liquidity, they may have little incentive to actively trade in the secondary market, thereby resulting in an even thinner market. In this context, we consider there is a strong need to maximise liquidity and transparency in the market and there is a high risk that liquidity is unlikely to develop without regulatory intervention, both to impose liquidity promoting obligations on ESB and to ensure there is a viable trading platform to facilitate secondary trading.

We consider the Mandatory Centralised Market option represents the best approach to concentrate liquidity while also ensuring transparency in what will likely be a thin market, exposed to the threat of market power. This platform must be available prior to market go-live.

Q3C: Do respondents believe that "back-to-back" trading to lay-off exposure to difference payments should be permitted?

It is not obvious how back-to-back financial arrangements could be restricted by the RAs given they would be purely financial transactions that would not alter any of the underlying RO obligations. As noted in the consultation paper, there are risks and circumstances that favour a "direct" transaction. There may be a role for financial arrangements where the cover required is a non-standard product or where the times are very short, but that may depend on the direct trading arrangements and the products available in that market.

Q3D: With respect to the creation of a centralised Reliability Option secondary market platform:

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

As we noted earlier, the secondary market for ROs is likely to be thin and a key concern is to maximise liquidity in the secondary market to provide risk management tools for participants. Anything that impedes such liquidity will increase the risk for participants which will ultimately impact on customers. The cost assessment is therefore between the cost of developing a trading platform relative to the cost to customers of an inefficient and riskier market for capacity providers that will inevitably result in higher RO costs through risk premiums being added to the RO bids. This could also reduce the ability of smaller participants to participate in the I-SEM which would be detrimental to competition in the long term and perpetuate dominance and the scope for market power.

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

PPB considers it is essential that capacity providers are able to acquire RO volume in excess of their de-rated capacity. Given the concerns already expressed in relation to the risk of thinness and illiquidity in the secondary RO market, this provides a means to create a modicum of liquidity.

Generators should be able to trade additional volumes up to their maximum export capacity.

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

PPB considers secondary trading should be available immediately following the conclusion of the primary auction. Trading should be facilitated up to as close to realtime as possible although the likelihood is that pricing close to realtime will be much more volatile reflecting greater knowledge of the supply:demand balance and hence the risk that there may be payment obligations under the ROs.

As we have already highlighted, there must be sufficient liquidity in the secondary market in ROs to enable generators to manage their exposures during outages. Planned outages are scheduled well in advance in accordance with the Grid Code provisions and therefore can be planned 18 months in advance of the outage. While this grid code process seeks to ensure outages are planned such that there remains a reasonable capacity margin, that may not be the reality as the actual outage approaches and hence generators will want to have mitigated that risk well in advance when the pricing reflects the expectation of little risk of scarcity.

Given the market illiquidity and the fact that it is unlikely there will be a single counter-party (other than possibly ESB) who could for example cover a full plant outage (400MW for the largest CCGTs), the products offered would need to be standard to maximise the fungibility in the market. Customised products would tend to distort the market and we consider standard products should be the primary products traded. Such products may not however be suitable if an RO holder is seeking to sell on their RO because they are exiting the market or can no longer provide the capacity (e.g. because of a catastrophic breakdown). However, there is unlikely to be sufficient surplus capacity available among existing RO holders to cover such an event and a different approach may be required to facilitate such a requirement where they would be seeking to engage with wholly uncontracted or mothballed capacity or potential new entrants.

We do not see any value in post event trading given the value of the RO will be known as the price will either be above or below the strike price and hence the liability will be known. Large portfolio participants such as ESB have an inherent advantage from their portfolio and can effectively offset across their portfolio. However we do not believe ex-post trading will provide any assistance to smaller participants given the pricing will be binary.

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

As we have already noted, the market will be illiquid and hence it would be essential to minimise any risk of barriers to trading by ensuring pre-qualification can occur throughout the year.

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

As already highlighted, liquidity is a major concern in the secondary RO market and any further disaggregation of the products through each product bearing different stop-loss limits will add further levels of complexity and tend to further dilute the liquidity in the market. Resetting the Stop-Loss limit to zero would ensure all secondary market products are standard and hence should assist with both liquidity and transparency. The arrangement would also complicate the administrative requirements to ensure an audit trail existed. Hence resetting the stop-loss to zero seems to be the most pragmatic approach. However, this is clearly simplest where the trade is an enduring trade but we expect most trading will be to assist participants manage their exposure during planned or forced outages and therefore the trades will tend to be for a discreet duration such as the period of a planned outage. We expect that on the transfer back, the stop-loss limit would not again be reset but that the originating holder's stop loss would recommence from the level it had been at prior to the short term transfer.

Chapter 4. ***Detailed Reliability Option Design***

Reliability Option Contract Length questions

As a matter of principle in relation to non-discrimination, PPB fundamentally disagrees with the proposal that only new entrants and re-furbished plants have access to longer term contracts and we consider that the same contract terms should be made available to all participants. We do not consider any of the arguments put forward in the consultation paper justify such a fundamental difference in the treatment of capacity providers. The product being secured under the CRM is capacity and if a provider can provide MW then there should be no unfair discrimination against existing providers, just because they have already made their investment but yet can offer the same capacity product for the same duration as a potential new entrant or another existing unit that requires significant investment. We believe that favouring new or refurbished capacity in this way is not consistent with the requirement to promote competition. In this regard, we note that while the EC provided State Aid clearance of the GB capacity mechanism that makes provision for longer term contracts for new entrants, this has been challenged on the basis of its discrimination against existing capacity which reflects our concern with the SEMC's proposals.

In relation to the point on "significant investment", an existing plant (unless very old) is likely to have significant capital investment outstanding (including debt) in relation to its asset. In aggregate terms the value may well exceed that of a "new" investment. For example a CCGT that has been operating for 10 years may have as much outstanding investment in monetary terms as the new investment required of a new entrant OCGT or for life extension works on another plant that has been operating for 20 plus years. Similarly all generating units require significant ongoing capital investment throughout their operating lives. This highlights the potential for discrimination if preferential treatment is selectively provided to some capacity, and also highlights that differentiating between different "investments" is extremely problematic.

Precedents in other countries

Slide 39 of the presentation made at the workshop on 20 January 2016 (SEM-16-003) says that international experience is varied, and the duration of "up to" 15 years for Great Britain (GB) looks like an anomaly. Other schemes have found it sufficient to offer 3-7 years, with the promise of relatively stable (annual) contracts after those contracts end. International capacity markets have explicitly rejected proposed moves to longer term contracts for new plant alone on the grounds that they are discriminatory towards existing plant and were unnecessary to attract new capacity.[1]

We understand DECC considered converting the “annual” price emerging from a capacity auction in GB into the equivalent price for a long term contract, using an estimated price duration curve, but all attempts to do so transparently and objectively failed.[2] The prospects for achieving any such conversion in the I-SEM, transparently and objectively, would be even more problematic, given its smaller size and lower liquidity.

Practical concerns

We foresee a number of difficulties with offering new entrants very long term contracts, apart from the obvious legal difficulties of discriminating between (or even defining) new and existing plant. In each annual auction, long term contracts may only be awarded to a minor share of participants. However, over a long period such as 15 years, these minor shares would build up to a substantial portion of total needs – perhaps even more than 100% if future demand failed to materialise as expected. (For example, if each annual auction resulted in only 7% of total forecast demand being awarded to new capacity, those contracts would cover 105% of total demand after 15 years, i.e. before the first contract had expired.) This possibility is a major risk for the All-Island market, given that existing generation was commissioned in bursts and hence is likely to require replacement at similar discreet points in future, and also because of the way demand forecasts have fluctuated in recent years and may so do again.

Recent history of EU electricity markets also highlights that the economic life of generator plant is not defined by its technical characteristics alone, but also by economic circumstances. Many CCGTs built to last at least 15 years have in practice been mothballed or closed completely within that time, because the market for gas-fired plant diminished (demand fall-off, subsidies provided to renewable technologies and low coal and CO_2 prices), and/or because their technology is already out-dated.

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

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

In any case, it would be wrong to overstate the importance of individual ROs for investment incentives, since they cover only a part of the costs of building new generation capacity. (In principle, capacity revenues may cover the fixed costs of peaking plant, but baseload and mid-merit plant have higher fixed costs that they must cover with energy sales.) The benefits of a CRM lies in its contribution to the stability of the overall energy market, not in the contracts per se. For this reason, although we can appreciate that investors might argue for longer term contracts, we cannot see any basis for discriminating between different (new and existing) providers, or for tying the duration of ROs to the parameters of project financing.

Conclusions

The somewhat anomalous approach taken in Great Britain, offering "up to" 15 years, therefore offers no useful precedent for the I-SEM.

Discriminating in favour of new plant may only saddle consumers with higher costs than necessary. Moreover, precedents from other regimes, and consideration of the technological and economic risks facing investors, suggest that a shorter period is more appropriate.

For reasons of administrative simplicity and non-discrimination, we favour a model that offers annual contracts to all generators, bolstered by the promise of stable revenues in subsequent annual auctions. We consider that this represents the best and most bankable solution for all and that any disparity of treatment of existing generators will be identified as "regulatory I-SEM market risk" by potential investors, requiring risk premiums for investment in the I-SEM that will ultimately result in higher costs for customers.

If new entrants must be offered a better deal than existing plants, then the examples of the 3-7 year contracts in other markets provide the best indication of what is required.

Q4A: Principle of Longer Term Reliability Options:

(i) Do respondents agree that plant requiring significant investment should be able to avail of longer term Reliability Options?

As identified in our detailed comments above, we consider it would be discriminatory not to offer the same contract terms to all participants. As we identify, there are significant practical difficulties selecting who would be conferred preferential rights of access to longer contracts given most plants will be continuing to make “significant investments” to enable ongoing operation and provision of capacity. Such discrimination can be highlighted by an example that considers the treatment of a unit that has been in operation for a year and which has 14 years of the “economic life” of its investment to recover which may be only marginally different to the investment of a potential new entrant that would be granted a long term contract.

We consider that equivalent contracts should be offered to all generators, be they one year or slightly longer term. On the assumption that the majority will be annual, the critical requirement for the CRM is to ensure there are stable revenues in subsequent annual auctions that would provide value to potential investors and participants with unremunerated investments alike. Any disparity of treatment for existing generators is also likely to contaminate the view of new investors and may well offset the perceived benefit of a longer contract.

(ii) Do respondents agree that existing plant should be restricted to reliability options with a term of 1 year?

No. As outlined in response to both the previous question and in our detailed introductory comments in the RO Contract Length questions section, we believe existing plants should have access to the same duration of Reliability Options as any other potential capacity provider, new or otherwise, whether that be annual, longer term, or some combination thereof.

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

If longer term Reliability options are to be made available, then they should be open for any participant who can commit to deliver capacity for that term. As we have already noted above, anything else would be discriminatory and most likely require arbitrary selection of eligibility to participate.

Q4B: Classification of plant as new, upgrade or existing

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

As we note above, all generating plants require significant investments at various times, be that because of major outages in a CCGT's outage cycle or sometimes as a consequence of compliance with environmental or other requirements (e.g. FGD, Low NOx investments).

Notwithstanding our objection to differential treatment of capacity in the I-SEM, if it is determined that plant requires classification as new, upgrade or existing, the assessment must be based on transparent and objective criteria that are pre-determined based on experience, evidence and expert judgement. There is no reason why a combination should not be utilised. For example if it is patently obvious based on the material tangible facts (e.g. new site, new connection, etc.), then that should be sufficient evidence. If there is doubt then the financial cost based criteria could then additionally be employed and if there is a dispute over these facts then an "expert" could be engaged to provide a judgement on the categorisation.

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

As noted above, if thresholds are to be identified then they would need to ensure they do not arbitrarily result in incorrect classification that creates further unfair discrimination, either against the party who is excluded in error or against others who are disadvantaged by the inclusion of a competitor in error. We consider that it is likely there will circumstances where the classification is not clear and we suggest that there needs to be a formal dispute resolution process to enable such cases to be determined. A concern would be if the thresholds are too low then a party who is a beneficiary in error is not going to challenge but there needs to be a mechanism for other parties to object and provide evidence. This could be facilitated through consultation on the evidence and draft decision to confer preferential status on any unit/project.

Q4C: Maximum available Reliability Option lengths

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

As noted earlier in this section, we believe there should be no discrimination. We also consider that if ROs are to be offered for terms greater than one year, these should be for the shortest duration possible. As we highlighted in our introduction to this section, it is entirely plausible that where 15 year contracts are offered, there could be a time in the future when all the capacity is contracted under long term contracts with a broad range of different prices. This could arise as coal plants are forced to close, most of the old peaking plants in Ireland were commissioned over 30 years ago and most of the CCGTs were commissioned between 2000 and 2010, and all of which could close over the next 10 to 15 years.

In addition, the price under any RO is likely to be related to the cost of a peaking plant and any investment in plant to fulfil other than a peaking role will need to capture the additional inframarginal rent in the Energy markets to provide a return for its investment. Hence the RO is not providing a full guarantee against fixed costs and potential investors will have to make assessments of other revenue streams as part of their investment decision. A stable and sustainable overall I-SEM market design will be more important to assist such investments than a 15 year contract.

If new entrants must be offered a better deal than existing plants, then the examples of the 3-7 year contracts in other markets provide the best indication of what is required. However, there is no reason to adopt such an approach initially and longer term contracts could be a fallback if the evidence is that investors are not committing to the I-SEM and that additional risk for customers, through contracts that extend beyond than 1 year, is merited and necessary. This should also be aligned with the DS3 contractual arrangements.

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

As is evident from our earlier responses, we consider the CRM should commence offering non-discriminatory one year contracts and only in the circumstances where it is clearly evident the required capacity is not entering the market should any longer term contracts be contemplated.

If such a requirement is demonstrated, then we believe the Shortest Economic Life approach with terms of 3-5 years is the most appropriate. We do not believe the GB approach offers any useful precedent and believe that the EC's natural leaning is for non-discrimination and that a stable, sustainable I-SEM market design will provide a better framework for appropriate investment.

We disagree with the assessment that long term contracts assist by ensuring the costs of entry are low when new capacity is required. Such an approach is likely to delay entry into the market to avoid artificially low costs and where low prices causes financial distress and the scope for disorderly exit of existing capacity then that will increase the perception of risk in the I-SEM and add additional costs for customers.

We agree that shorter contracts will enhance competition and again highlight the risk that nearly all of the capacity could be contracted if 15 year contracts are offered which would remove all competition.

We also note that long term contracts are likely to create a barrier to change and would require substantial legal drafting, if they are to have any value, for Changes in Law events, etc. This will add further risk for customers.

In relation to stability and efficiency, the outturn is likely to be a portfolio of long term contracts all with different prices. The risk is that the prices could be higher or lower than they should be as long term contracts effectively means a reversion to centralised planning with customers being required to bear stranded cost risks for decisions made by the RAs/TSOs. It is also unclear whether the perceived benefit of offering a long term contract for new capacity is offset by the perception of regulatory risk arising from discrimination against existing market participants.

We also consider that there should be no technological segregation which would add further complexity to the arrangements, require further decisions that may be arbitrary and discriminatory, opening up further potential for dispute and challenge.

<u>Stop Loss Limits questions</u>

A liquid RO secondary market and Stop Loss limits will provide risk management tools for participants to manage the risks associated with ROs.

At a high level, we consider that the annual Stop Loss Limit should be set such that the potential loss under an RO contract cannot be more than the revenue received. This still provides significant incentives on RO holders to be available since any loss means they would not be capturing the "missing money" that they require under the scheme. This provides a significant incentive with the Stop Loss providing participants with protection from excessive downside risk that could threaten their ongoing viability.

Administered Scarcity Pricing creates a high risk to shorter term cashflows and hence monthly and daily limits will assist participants in the management of this risk.

Pricing in the Balancing Market is still being considered and the implementation of Administered Scarcity pricing remains uncertain. It would therefore seem prudent that the final design of the Stop Loss limits will require further consideration once these design elements are finalised.

Q4D: Do respondents favour the I-SEM Capacity Year running from October to September, with annual stop loss limits applying over that I-SEM Capacity Year?

The annual stop loss limits must align with the I-SEM Capacity year, however the capacity year is defined. We are not aware of any requirement for the capacity year to be changed to run from October to September and given there cannot be assurance at this stage that the I-SEM go-live will not slip, they may be a requirement for contingency transitional arrangements in any case.

Q4E: Do respondents believe that "per event/day" and "per month" limits are required in addition to the annual stop loss limit?

Potential pay-outs under the ROs could be significant and create a significant risk to the ongoing solvency and viability of a participant (particularly non portfolio participants) and monthly stop loss limits would assist with the management of cash flow risk for CRM participants. PPB considers monthly stop loss limits are required.

For similar reasons, per event/daily stop loss limits, may be required, particularly if the Full Administered Scarcity Price were to be immediately set to VOLL in which case even a single daily payment could be substantial.

Q4F: Which approach do respondents favour for the definition of the Per Day/event limit?

We agree that the definition of an “Event” is likely to be problematic and therefore we consider it would be simpler to just set any shorter term limits on a settlement day basis.

Q4G: Please provide views on the appropriate levels for the each of the proposed stop loss limits.

As we note above, there remains significant detail to be finalised on the design of the I-SEM balancing market and on how Administered Scarcity Prices interacts with that. In the absence of a definitive design decisions in these areas, our provisional thoughts are that the Annual limit should be capped at the RO payments received (i.e. x1).

Monthly limits would need to be consistent with this annual limit and rather than being twelfths of the annual limit, they could be weighted to reflect demand or an ex-ante estimate of the risk (in a similar way to the current SEM CRM methodology operates).

If daily limits were applied, an ex-ante forecast may be more difficult and it may be simpler to apply weekday and weekend/holiday weighting factors.

Commissioning Window and Implementation Agreements questions

A key feature for the auction process must be to ensure, to the maximum extent possible, the capability of potential participants to deliver should they be successful in the auctions. If this is not properly managed then there is a high risk to security of supply, not just as a consequence of the capacity not being delivered but also because of the depression in the CRM clearing price that will affect all other participants in the I-SEM. In such an event, the pricing must be recalculated to exclude the phantom capacity to determine the clearing price that should have been determined.

Q4H: Is a period of four years from the Auction Date to the start of the first Delivery Year appropriate?

We believe a four year lead time should provide sufficient time between the Auction Date and the first delivery year. However, this will likely only be the case if the pre-qualification requires that potential projects have key consents and agreements in place (e.g. connection agreements, planning consent etc.) since otherwise there would be a high risk that projects could not reach substantial completion on time.

Q4I: Does setting the Long Stop Date at 18 months after the start of the first Delivery Year strike the correct balance between the costs incurred by the market and the ability for delayed or longer-running capacity projects to be completed?

Long stop dates are only relevant where long term contracts are being offered. As noted earlier, we do not believe there should be discrimination between existing and new providers and hence if only single year contracts are offered, long stop dates are not relevant. If longer term contracts are offered (including to existing capacity) we consider an 18 month long stop date would be appropriate. It isn't clear whether any such delay also extends the expiry date of the contract although we believe the expiry date should be fixed which would provide a further incentive to commission the plant on time or with minimal delays. There is a further query where the delay is caused by delays to the connection. While it is appropriate that the project is not penalised for such delays, it is less clear whether the long stop date and possibly the contract is extended to compensate or whether the TSOs should be liable. Any extension should not detrimentally affect the capacity in the market who are meeting their obligations.

Q4J: Are the proposed milestones reasonable?

We consider the milestones to be generally reasonable although their interpretation may need further clarification to account for the alternative technologies that may emerge.

Q4K: Are there any other milestones, especially prior to Substantial Financial Commitment, which could be used to add security to the delivery of new capacity?

A key risk is consents and we believe the obtaining of all necessary consents should be a pre-qualification requirement rather than being a milestone to be met after being awarded a contract.

Q4L: What proportion of the contracted capacity is appropriate to use to identify Substantial Completion?

The GB definition of Substantial Completion, which requires that capacity is capable of producing 90% of its Reliability Option capacity, after de-rating, seems reasonable and we would support adopting the same standard.

Q4M: Is six-monthly reporting appropriate?

Again we would support adopting the GB approach with independently verified reporting against four key milestones every six months. We would similarly support the reporting changes that are currently subject to consultation. It is even more critical for a small system to obtain early warning of any project delays or potential abandonment and hence there must be appropriate information exchange throughout the period from contract award to substantial completion.

Q4N: Do any (or all) of the reports need to be independently verified?

We consider the formal six monthly reports should be independently verified.

Q4O: Does 18 months provide sufficient time after the Auction Date to achieve Substantial Financial Commitment?

We consider 18 months is a reasonable period between the Auction Date and Substantial Financial Commitment milestone.

Q4P: Is it appropriate to terminate a Reliability Option for failure to achieve Substantial Financial Commitment?

We consider it is appropriate to terminate the Reliability Option if a Capacity Provider does not achieve the Substantial Financial Commitment milestone. There may be a case, in limited circumstances, for an extension to the milestone date where there is a delay capable of remedy and which is not expected to impact on Substantial Completion.

Q4Q: Should failure to achieve any other milestones (within a suitable window) trigger termination of the Reliability Option?

We consider termination should be limited to failure to achieve Substantial Financial Commitment or failure to achieve Substantial Completion. Once financial commitment has been made there should be sufficient incentive to reach completion and there will most likely be a range of contractual arrangements in place to incentivise delivery, notwithstanding any performance bond that is required to be in place.

Q4R: Is it appropriate to partially terminate a Reliability Option if it can achieve 'Minimum Completion? What level should be set for Minimum Completion?

We consider it would be appropriate to partially terminate an RO if the capacity provided is lower than was originally envisaged and upon which the de-rated capacity for the provider was based. This would clearly need to be invoked prior to the Long Stop date and the de-rating factor may require re-assessment. The remainder of the capacity, if/when it is commissioned, should then be eligible to participate in all subsequent auctions or in the secondary market (i.e. not sterilised). The draw down on the performance bond will compensate customers for the non-delivery. We have no strong view on the Minimum Completion Threshold and are not clear what the justification is for the 50% used in GB. It is also possible that different thresholds could be viable for different technologies (e.g. if there were no impact on the flexibility of the capacity then there may be no require for any minimum, whereas if below a particular capacity the capacity was totally inflexible then perhaps the minimum should be set at a level that ensures no reduction in operational flexibility).

Q4S: If a Reliability Option is terminated under the terms of the Implementation Agreement, should this project be 'sterilised' for a period of time following the termination and be unable to participate in capacity auctions?

We do not see why termination should result in sterilisation of the project. If the performance bonds are appropriately set then customers will have been protected and it would seem unreasonable to exclude such capacity from future auctions and therefore we believe such capacity should be eligible for the same contracts as are available to existing capacity although clearly the de-rating will need to be carefully assessed to ensure any performance issues are appropriately reflected in its de-rated capacity.

Q4T: Should the I-SEM consider terminating Reliability Options if the information submitted as part of the qualification process is discovered to be false or mis-leading?

This is clearly a bigger issue where long term contracts are being offered although as we outline above, we believe there should be common contract terms offered to all potential capacity providers (new or existing).

If the pre-qualification process is robust then there should be limited risk of such an outcome. However, if it is discovered that there was intent to mislead then it would be appropriate that ROs could be terminated in such circumstances.

Q4U: Do respondents agree that the level of the performance bond should be based on a pre-estimate of the cost to the market of non-delivery of contracted capacity?

The cost to the market of non-delivery of contracted capacity is not a precise figure and the value could vary widely depending on what assumptions are used in the assessment and the prevailing market conditions at the time of the assessment. For example if a new generating unit is planned but is delayed meaning closure of an older unit is postponed, the risk to security of supply may be negligible.

There will have been a cost to other capacity providers who would otherwise have seen a higher price in the year and hence they should be compensated such that their price is re-based to the rate that would have resulted if the delayed capacity had not been successful in the auction. Again it is arguable that the full cost of this should be directed at the new capacity provider since in the counter-factual customers would have been paying that higher price.

It would therefore seem more appropriate to base the level of the performance bond on the standard terms that normally apply in EPC contracts. This is likely to be more normal and transparent for financiers and hence reduce the risk of financing premiums. Simple options could be either a percentage of the overall investment cost (if that can be objectively confirmed) or a percentage of the value of the RO.

Q4V: Do respondents agree with the principle that the level of performance bond should rise over time, reflecting increased costs to the market? If not, what alternative principle should be used and why?

We agree with the principle that the level of the performance bond should rise over time, although not because of costs to the market which, as we noted above, may be negligible, but to provide an incentive for early communication of failing projects that will provide more time to fill the gap. However it creates a further level of complexity that may add little value overall value.

It is likely that there will be significant financial commitments made by investors who will have strong incentives to see successful project completion and hence there should be reasonable alignment of incentives. If the level of the bond is to increase, it should not therefore need to be penal.

Q4W: At what level in €/MW does the performance bond create a serious barrier to entry? Does this differ for small vs large plant or for different technologies?

We cannot comment on what level would represent a barrier to entry, however given it is not always obvious that a delay will result in a high cost for customers, we consider that the performance bond should be derived on a common basis for all providers.

Q4X: Do respondents agree with the principle that use of a fixed €/MW level for all participants, regardless of size, to set the size of the performance bond does not fully capture the costs and risks to the I-SEM and that a more complex approach is needed? Do participants have an alternative preferred method for handling the greater risks to the I-SEM created by larger new capacity projects?

Demand growth in the I-SEM is not as high or volatile as it was in the past and the support for renewable investment means that for the foreseeable future, large capacity projects will be developed to replace existing capacity rather than to meet demand growth. In such circumstances the capacity that is planning to retire once the new capacity is commissioned, is likely to be able to continue to operate for a period should there be a delay. This represents much lower risk for customers than when demand in Ireland was growing at c10% p.a. Therefore while in theory larger projects would carry greater risk for the market should it fail to commission on time, new entry is more likely to align with the closure of equivalent capacity and hence the risks are unlikely to be much different for a large unit than for a small unit. Further, large projects will require significant capital investment and once financial close has been passed, there will be very significant incentives to complete the project in a timely manner.

Q4Y: How should the level of the performance bond change over time? Should this have any link to the milestones?

We have already covered this in our response to question 4V.

Q4Z: Do you consider that the Time To First Delivery (/Time to LSD) proposed here for the CRM should also apply equally to the delivery of System Services under the DS3 arrangements? If you consider that the time (s) should be different, on what basis / what rationale should they differ?

We believe the CRM and DS3 arrangements should be aligned as far as is practical. There is however the issue that the levels of revenue earned in one will, to some extent, affect the revenue requirements in the other. We expect the revenues earned under DS3 will be lower and hence it would be preferable to know the results of the DS3 auctions to inform a provider's revenue requirements and bidding strategy for the RO auctions.

Administered Scarcity Pricing questions

Administered Scarcity Prices (ASP) create the primary incentive for capacity providers to perform under the ROs. The detailed design of pricing in the Balancing Market remains under discussion and the operation of ASP with the BM requires further consideration once the BM pricing arrangements are decided. Consideration of the TSO's operation of the system will also be required to ensure ASP are driven by market fundamentals and not by TSO actions.

A further issue is at what point Administered Scarcity Prices are determined and how these are used. In the absence of market coupling of balancing markets, realtime trades can only be concluded by the TSOs under SO-SO trading arrangements. The TSOs may have a complete price curve of INCs and DECs submitted under the BM arrangements that has a maximum incremental price of for example €1000/MWh. If the supply/demand balance in the I-SEM market was at a position with just enough reserve, then it is uncertain what happens it the TSOs decided to export energy to GB to assist a severe shortage in the GB market. It would need to be determined in the first instance whether such a trade should be permitted. If it is, the question is at what price should the trade be concluded at, and also whether such a trade that would trigger ASP should actually result in an ASP price in the I-SEM. Similar rules are likely to be required for other TSO actions (e.g. TSOs failing to dispatch sufficient reserve which results in extensive load shedding) to ensure there is clarity over the the events that trigger the application of ASP.

As already mentioned, coupling of the BMs are not yet required but this is an EU ambition for the development of energy markets. It would therefore seem prudent to consider how ASP would interact with the BM price curve and whether this would influence, for example the design decisions for a five-part piecewise linear function.

ASP will introduce the potential for significantly higher prices than exist in the SEM. This magnifies the risk for participants who therefore need to be able to rely on liquid risk management opportunities to enable them to manage this risk This requires an effective forward market, sufficient flexibility of order types in the DAM, a fully functioning IDM, a liquid secondary RO market and appropriate Stop Loss limits on the ROs, all coupled with effective market power mitigation measures in all of these markets. There is also a requirement to define exceptions where the RO does not bind, e.g. where the unit is available and participating in the BM but for whatever reason is not dispatched by the TSOs, to ensure participants are not exposed to unmanageable risks arising from TSO actions/inactions.

In the absence of these risk management tools, generators would be heavily exposed which could result in insolvency and disorderly exit or higher risk premiums being required in the RO auction, or both.

Q5A: Which of the options do respondents prefer (and why) for the enduring level of the Full Administered Scarcity Price (FASP)?

- ***(i) VoLL;***
- ***(ii) EU Consistent (e.g. with GB);***
- ***(iii) Euphemia Cap; or***
- ***(iv) Existing SEM PCAP***

A key consideration for the enduring value of the FASP is that it should not create distortionary incentives for cross-border energy flows. It would be unacceptable for electricity to flow to GB, maintaining customer supply in GB while shedding I-SEM customers because a disparity in the price caps in the two markets, unless there is a genuine reason why customers value lost load materially differently.

On this basis, we consider the enduring level of the FASP should be set consistent with the GB price. However, given that the I-SEM is a radically different market with very different risk exposures for participants, and that the coupling of the balancing markets is not yet a requirement, we believe there is merit in transitioning to such alignment from, for example, the Euphemia price cap.

However, as noted in our introductory comments to this section, our support for higher FASP is contingent on the full range of risk management tools being available for participants to enable them to manage the additional commercial risks that arise from higher prices.

Q5B: Do respondents agree with the definition of full load shedding (when Full ASP applies) as set out [i.e. paper references EirGrid Red Alerts and envisages that load shedding would be deemed to have occurred when any of the following three events has actually occurred – (1) the system frequency has deviated significantly below normal levels; (2) system voltages have deviated significantly below normal levels; (3) customer load has been (involuntarily) shed]. If not please explain why, and your proposed alternative definition.

We have concerns that the proposed definitions do not result in a simple objective criteria for assessing when full ASP should apply. We note the RAs clarification to the EAI query in relation to paragraph 5.3.10 of the consultation paper which indicates ASP will not apply when there is sufficient available capacity even though it may not be able to respond in time. This avoids the TSOs' dispatch decisions from confusing the situation and having to determine rules to account for such decisions. However, the TSOs' decisions are also relevant to system frequency and voltage deviations and hence there would need to be rules to determine if exceptions are required for some occasions when these would otherwise trigger FASP.

Similarly customer load shedding does not reflect the point at which demand exceeds supply. The TSOs typically disconnect customers before they reach the point of demand:supply balance to retain a reserve margin and hence the TSOs' actions could have a bearing on when FASP would be triggered.

The proposed approach also requires a determination of what is meant by "deviated significantly below normal levels" for which there is not a straightforward conclusion.

We believe it would be better to avoid such situations which are somewhat subjective and are likely to vary in each circumstance. A more objective approach would be to define load shedding as the point at which demand, before load shedding, exceeds the available capacity. This is a more readily verifiable test that does not depend on any TSO action or inaction.

Q5C: Do respondents agree that virtual bidding removes any incentives on capacity providers to withhold power from the DAM or the IDM to sell in the BM? Do you agree that this applies regardless of what market power controls are placed on DAM, IDM and BM bids? Do you agree that this applies regardless of the level of the Full ASP? If you do not agree, please explain why.

Virtual bidding, if employed on a widespread basis when scarcity is expected, would result in scarcity in the DAM with prices fixed at the DAM price cap but with volume allocated potentially on some pro-rated basis across the demand in the DAM (including the generator buy bids). The detailed design of the energy market is still in progress but we are not aware of any proposals on now the virtual bids would be applied. This could be achieved by netting off the DAM buy and sell volume leaving a lower initial PN and an obligation to provide INCs to the BM or the virtual unit could be kept separate and effectively just spill into the BM. However, under either approach, it is not clear to us that this does not effectively result in the capacity being withheld from the DAM.

Market power is likely to remain an issue since a dominant generator will have more market information and therefore may have greater advance information on the risk of scarcity and could therefore extract greater benefit from virtual bidding. This requires further consideration as part of the market power considerations.

The relationship with the energy market is difficult to assess given the detailed design of the energy market is not yet complete. It would be useful to reappraise the situation once the design is concluded to ensure there is consistency.

Q5D: If stakeholders consider that it is appropriate to set the Full ASP at a lower level for an introductory period they should also set out, how long that introductory period should be and why, or alternatively the principles that the SEM Committee should employ in deciding when to move from the introductory full ASP to the higher rate full ASP.

As noted above we consider a transition should be adopted. The minimum transition period should be four years which would align the transition to the enduring FASP with the first year of delivery under the first auction. It is important that the enduring level of FASP is known prior to the auction as that will be one of the key elements that will be required by participants in the formulation of their bids.

It may also be prudent to hold the initial level of the FASP (e.g. at the Euphemia price cap) for at least the first 2 years to enable the new I-SEM market to bed in and to ensure all the markets are functioning effectively and that the market power mitigation measures are operating as required.

Q5E: If you favour a different level of Full ASP, either for an introductory period, or after any introductory period, please indicate the level and justify your response.

Our views on the level of the FASP are set out in our response to Question 5A above.

Q5F: Do respondents agree with the proposed approach of using a static approach to setting the piece-wise linear ASP function at the inception of the I-SEM, and if not why not? If yes, do you agree with the proposed approach of setting the piece wise linear equation as a function of the remaining MW of available operating reserve?

We agree that the proposed static approach is appropriate for the I-SEM although it isn’t clear whether a 5 piece linear curve is sufficiently granular. In line with our comments on the definition of load scarcity, we believe there are benefits in simplicity and predictability. We also favour this static approach as the enduring methodology.

The proposed approach for setting the piece wise linear equation as a function of the remaining MW of available operating reserve seems reasonable given the wide range of permutations that could result in the available margin (as the clarification to the EAI confirmed to be the correct interpretation of para 5.3.10) being between the required maximum reserve margin and zero. We would not expect this curve would vary greatly from year to year and if this is confirmed then it may not be worth varying the curve annually.

Q5G: What should the value of X in Figure 12 be?

We believe there needs to be some degree of continuity in prices and it would therefore seem rational to start Administered Prices at the RO strike price. Hence X would be a figure such that X * FASP = RO Strike Price. Where the level of FASP transitions to an enduring FASP the value of X should also transition to ensure the price at point B remains equivalent to the RO Strike Price.

Q5H: How far in advance of the start of the Capacity Delivery Year should the piece-wise linear function be set. Does this need to be before the T-1 auctions?

The function must be set prior to the RO auction since any change to the shape or magnitude will affect the level of payments that will be required under the RO, which will be a significant input to the prices a capacity provider will be submitting into the auction. As we noted in response the Question 5F, we would not expect the shape of the curve to vary much given it will be a blend of a large number of permutations and therefore do not believe this should be a significant concern.

Q5I: Do respondents think that any changes need to be made to the governance of the target operating reserve policy. If yes, what are these changes?

We are unclear as to what information is being sought and hence cannot respond to this question.

Chapter 5. *__Transitional Issues questions__*

Q6A: Which of the suggested options (annual auction, block auction, do nothing) do you prefer?

We are disappointed the consultation paper does not present a “Glide-path” option as was initially discussed at the workshop on 29 September 2015.

We consider such a “Glide-path” approach represents the simplest transitional measure and avoids all of the concerns identified in the consultation paper in relation to the other options, including in relation to significant Market Power risks under Option 2 (Auction as a Block) and the risks identified in relation to security of supply should there be disorderly exit prior to the end of the transition period.

A “Glide-path” transition is also a practical approach that is naturally time limited and does not introduce additional risks for participants who will have many other new risks to manage in the transition to the I-SEM. Market participants already face a challenging programme to be ready both operationally and commercially for the commencement of the I-SEM which will require radically different risk management and trading approaches for the energy markets. Preparation for the first main CRM will similarly be very challenging given it will largely be a blind process as there will not have been any actual experience of the operation of the Energy Markets or the Ancillary Service Markets to inform participants bidding strategies.

This, of itself, never mind the wider Energy and DS3 market changes represents high risk for providers. The proposition of adding in a further one-off Block auction process for the transition period will require futile effort that will divert attention and resources that would be better utilised on the other market changes. A similar problem exists, although to a slightly lesser extent, with Annual auctions. These would similarly be resource intensive albeit the process would be more closely aligned to that required for the first main auction.

We believe it would be better to avoid these risks by adopting a “Glide-path” transition between the SEM Capacity rate and the outcome of the first main auction. We believe such an approach should be presented to the EU as part of the package of reforms that the I-SEM will deliver and that transitional arrangements that are naturally time limited can be justified as part of the radical transformation of the energy market in Ireland.

If such an approach is rejected by the EU, then we consider the least worst alternative to be annual auctions.

Q6B: If you prefer the do-nothing auction, do you believe this should be accompanied by relatively low levels of Administered Scarcity Price?

We do not support the do-nothing option as it will result in disorderly exit and would disproportionately affect smaller participants thereby increasing the market power of ESB which would be counter-productive for competition in the I-SEM, distorting all elements of the market.

Q6C: Are there any other transitional issues respondents feel that we should take account of when implementing the CRM?

There are a number of issues both within the CRM workstream and in the wider I-SEM implementation that affect the implementation of the CRM. Administered scarcity pricing could result in large and unmanageable commercial risks for participants if participants cannot manage their risks. We have already identified most of the elements that are required to help manage these risks above but we summarise them again below for completeness:

(i) A liquid forward contract market is needed to allow participants to hedge their longer term price and revenue volatility;

(ii) The DAM must provide maximum flexibility in order types to allow generators to manage their scheduling risk;

(iii) A liquid, transparent and fully functional IDM is needed to enable refinement of positions and to enable generators to trade themselves into a feasible dispatch position (particularly during scarcity events – subject to next point);

(iv) Clear RO exemptions must be identified to ensure RO holders are not penalised when they are available and have bid into the BM but for whatever reason have not been dispatched by the TSOs;

(v) A liquid secondary market for ROs must be availablel to allow generators to manage financial exposures associated with planned and forced outages;

(vi) Market Power Mitigation measures are functioning effectively to counteract ESB’s dominance in each of the markets, including measures to promote liquidity and bidding restrictions in the RO auctions with particular concerns in relation to ensuring a price floor;

(vii) Appropriate stop loss limits to protect existing participants from bankruptcy and to remove potential barriers to new investment.