I-SEM – Capacity Remuneration Mechanism Detailed Design Consultation Paper SEM-15-014

Moyle Interconnector Ltd response

February 2016

Preamble

As an interconnector owner, we welcome the efforts of the regulatory authorities to develop arrangements for cross-border participation in the I-SEM CRM. From review of the consultation paper it is clear that a great deal of effort and consideration has gone into developing a variety of options and our response focuses on this cross border aspect while also providing comment on certain other parts of the consultation.

We have long seen significant difficulty in facilitating cross border participation by specific generating units in national capacity mechanisms. Our view is that if this was to happen it should be on a consistent basis across the EU rather than in an ad hoc manner across a limited number of borders.

Even with an EU wide approach, it is debatable whether this is appropriate for generators at the remote end of a HVDC interconnector. Within a synchronous area, a generator outside a national or bidding zone border explicitly contributes to security of supply on both sides of the bidding zone border as the power it generates will naturally flow across AC lines. With a HVDC interconnector this does not happen and its control system needs to be explicitly 'told' what power to flow. Without this instruction, an increase in generation has no impact on the interconnector flow[1] so no impact on meeting security standards at the remote end. A generator therefore can have no direct impact on interconnector flows.

As discussed in the consultation paper, a generator may only potentially influence interconnector flows through participation in various market timeframes to influence the local market price – again, there is no guarantee that such participation either reduces costs or improves security of supply in the remote market. The outturn market price and interconnector flow will be determined by the balance of supply and demand in that market as a whole so it is difficult to see the security of supply value in targeting capacity agreements at a limited number of specific market participants.

Cross border capacity benefit is supplied by the interconnector providing access to the entire cross border generation fleet. This, together with the complexity of any other arrangement and the desire to have some consistency with neighbouring capacity mechanisms, leads us to the view that an interconnector led approach is the appropriate route for cross border participation in the I-SEM CRM.

It is not feasible to target a capacity mechanism at an entire cross border fleet and it is difficult to see that a specific generator on the other side of an interconnector is as valuable to a bidding zone's security of supply as a generator located within that bidding zone. The former is subject to both its own reliability and that of the interconnector which makes it less reliable than generation located within the bidding zone. On the other hand, with an interconnector led approach it is reasonably safe to assume that power will be available at the remote end of the interconnector as the interconnector has access to the entire generating fleet of the markets it connects (subject to market prices determining the flows or TSO intervention such as countertrading).

[1] Other than perhaps frequency response services that would be triggered if the frequency rose significantly

CONSULTATION QUESTIONS

INTERCONNECTOR AND CROSS-BORDER CAPACITY

A) 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).

Our preference is for an interconnector led availability based approach. An interconnector led approach creates a more direct investment signal to improve security of supply, is significantly less complex so easier and less costly to deliver and likely to be less susceptible to gaming.

We find it conceptually difficult to consider that a specific generating unit at the remote end of a HVDC interconnector provides a significant contribution to meeting the security standard of the local market. We can see the argument that stimulating investment in generation in the adjacent market is beneficial (at least to some extent) to the local market. However, the extent to which such capacity would need to be de-rated (accounting, for inter alia, generator availability, interconnector availability, losses and likelihood of physical delivery) to reflect a GB generator's marginal contribution to meeting the security standard in I-SEM means that an I-SEM reliability option is unlikely to be a significant part of a GB generators investment decision. In addition, GB has its own capacity mechanism aiming to deliver sufficient capacity to meet GB demand (including interconnector exports from GB) so this should provide reassurance that sufficient GB capacity will be delivered without the GB market being 'topped up' by I-SEM reliability options.

The focus of the I-SEM project is market integration. This is best achieved by having consistency in neighbouring markets. The GB market has an interconnector led capacity mechanism and so the benefits of a consistent approach should be a significant part of the equivalent I-SEM decision[2]. A large part of the rationale for the GB decision to implement an interconnector led approach was that it avoided the significant complexity that a generator led approach would entail. It is recognised that the GB decision was viewed as an interim measure until an EU wide approach was developed and it seems sensible to follow a relatively simple approach for I-SEM. It appears that alternative approaches would require a significant amount of international cooperation to bring to fruition and, should the EU end up pursuing a different approach, they may be very complicated to remove or change. The experience of SEM, where capacity payments contributed to inefficient scheduling of interconnectors should be borne in mind here.

The 'product' provided by interconnectors to a capacity market is somewhat different to other providers given their particular characteristics. Under the EU target model the interconnector flow will be determined by market prices, with market coupling implemented at the day ahead stage followed by continuous implicit intraday trading. The interconnector owner therefore has no role in determining the flow as all capacity is made available to the market. Notwithstanding this, it is reasonable to expect that correct pricing signals will elicit a response from interconnector flows. If this does not happen it would be indicative of a market failure and is not therefore something that an interconnector owner should be penalised for.

We agree with the issues raised in the consultation paper regarding an interconnector owner's exposure to difference payments and that the availability approach mitigates these. The interconnector owner does not receive the I-SEM market price and has no ability to influence same

[2] The GB capacity market is not based on reliability options so references to consistency here relate to the interconnector or generator led approaches to cross border participation.

(beyond maintaining the interconnector availability). The standard difference payments regime is therefore not appropriate under an interconnector led approach as it places a large quantity of uncontrollable risk on the interconnector owners. The interconnector's main source of income is determined by the result of FTR auctions held well in advance of real time. These auctions will value FTRs based on the expected day ahead market spread but it is unlikely that auction bids would include a premium for scarcity that may or may not arise at the day ahead stage. As noted, scarcity may well arise in the intraday and balancing timeframes and there is no mechanism for the interconnectors to generate any revenue from scarcity in those timeframes so it is illogical for an interconnector owner to be exposed to difference payments relating to intraday and balancing prices. The interconnectors would therefore be exposed to significant unmitigated difference payments in a performance based regime.

Our view is that interconnector performance of their capacity option should be determined by declared availability rather than delivered energy. Since the interconnector does not receive any income from the I-SEM energy markets and difference payments should be capped at the level of reliability option fees payable to the interconnector owner[3]. To do otherwise would undermine any investment incentive that reliability options intend to create:

a. This eliminates the issue of inequitable penalising of interconnector owners for market failures causing failure to deliver.
b. It recognises the fact that SONI/EirGrid, with the agreement of the neighbouring TSO and subject to availability, always has the ability to change the interconnector flow if required
c. Monitoring performance is simple as interconnectors already have to publish their availability at an hourly resolution for transparency purposes
d. Recognises the capacity value of interconnectors and offsets costs to be recovered from TUOS customers

<u>B) 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?</u>

De-rating of interconnectors should be based on forward modelling of expected future performance. As the paper notes, historic analysis will result in de-rating being skewed by defunct market features that will not be relevant for I-SEM.

The SEM does not lend itself well to reacting to short term price signals due to being a mandatory pool with long date closures and ex-post pricing. The SEM gate closures are at least 10 hours ahead of real time[4] with interconnector schedules being fixed at these gate closures. Because of these long gate closure times, the lack of flexibility and misalignment with the shorter GB gate closure times there has been no way the SEM interconnectors could historically react to stress events and subsequent pricing signals. This should change when the target model is implemented via I-SEM by 2017 but means that historic analysis of interconnector flows is of little value when considering periods post 2017.

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[3] This would be consistent with GB capacity mechanism where penalties for failure to deliver are capped at the value of capacity revenue received

[4] There are 3 gate windows with closure 21.5hrs, 19.5hrs and 10hrs ahead of real-time

It therefore seems illogical that the de-rating of interconnector contribution to the I-SEM security standard should be in any way related to market structures which will not be present at the times contemplated by reliability options.

One additional reason for using forward modelling rather than ex-post historic analysis is that, the application of the latter methodology will not be possible for any new interconnectors. This means that de-rating of new interconnectors will have to be done via modelling. This leads to inequitable treatment of the same class of technology as the two methodologies will give different results.

De-rating of interconnectors should focus on technical reliability which can be easily assessed with reference to historic and publically available availability data. This should include communication with the asset owner to understand how well historic data is likely to predict future reliability e.g. if refurbishment has taken place to eliminate a cause of previous downtime.

As stated previously, the full capacity of Moyle will be made available to the market which will determine the flows based on pricing signals so there is an argument that there should be limited de-rating based on likelihood of flowing in the desired direction at times of system stress as correct pricing signals would ensure this happens.

<u>C) 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.</u>

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 per above, we do not support this performance based approach but are providing feedback to assist the assessment of this option.

We agree with the view that complex power flow modelling is likely to be excessively complex in the context of what it is trying to achieve.

The issue at hand here is unclear as the description of the former two approaches is brief but seems to be misunderstand the fact that a HVDC interconnector will only flow as instructed and the power that flows is not determined by electrical resistance or physical network characteristics (unless these play a factor in a decision to schedule a flow in a certain way). It therefore seems that the balancing market will need to allocate contracted flows to specific interconnectors as any change to the physical interconnector flows will need to be scheduled. If that is the case, then this question is irrelevant as there will be a clear link between contracted and physical flows on a specific interconnector.

Notwithstanding the foregoing, we assume that only the marginal flow on the interconnectors that has not been attributed to day ahead or intraday flows would need to be allocated to contracted flows from the balancing market. In this case, the pro-rata to meter approach seems appropriate as this seems most likely to give the correct result as it looks at actual power flows.

<u>D) 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?</u>

We do not favour the FTR led approach but wish to raise a number of potential issues with it.

With regards to question D, the net allocation approach seems most likely to produce the most accurate and fair result.

The issues described above in relation to a generator at the remote end of a HVDC interconnector not being able to significantly contribute to a security standard also apply to this approach. An FTR holder may only indirectly influence an interconnector flow through day ahead market participation but only as one participant in a large market. As the consultation notes, holding an FTR does not incentivise participation in the intraday or balancing timeframes, further diluting an FTR holder's relevance to I-SEM meeting capacity needs at times of system stress.

The discussion of this option seems to assume that the holding of an FTR should be a pre-requisite for participation in capacity auctions. If this option is the eventual preference of the NRAs this should not be the case. The holding of an FTR should be part of the performance criteria under a cross border reliability option. This removes the issues discussed of the misalignment of FTR auctions with capacity/RO auctions. FTR auction timing and quantities are determined by interconnector TSOs and are increasingly influenced by European network codes and regulation[5]. It is therefore unclear that such auctions can be scheduled around capacity/RO auctions. On the other hand, capacity/RO auctions will be within the gift of local NRAs so can be scheduled/tailored as necessary.

If FTR auction held before the RO auction, the value of the latter is unknown and the value of the former is a forecast so it is unclear whether there will be significant upward pressure on the FTR auction price i.e. interconnector investment signal may be muted. If RO auction is held before the FTR auction, then the cross border RO holder knows what income is at risk if they are not successful in acquiring equivalent FTRs. The upward pressure in FTR auctions is more likely to be evident leading to an investment signal towards interconnector owners.

At a high level we would propose that capacity auctions operate as follows:

1. Participant in RO auction registers as a cross border participant
2. Auction is held and cross border participant successfully bids for XMW of ROs. The participant is then obliged to hold at least XMW of FTRs for the duration of the period to which the RO relates
3. The participant may then acquire FTRs across the various timeframes over which they are offered (e.g. simply buy an annual FTR or choose to buy them on a month to month basis in monthly FTR auctions)
4. If the participant does not provide evidence of an equivalent FTR holding, they are deemed to have not performed in respect of their reliability option.

<u>E) 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?</u>

[5] For example, the network code on Forward Capacity Allocation requires development of a regionally coordinated methodology for splitting long term cross zonal capacity

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

As discussed above we do not support the provider led approach as we do not see that this will deliver security of supply benefits for I-SEM. It is therefore unclear how this option would deliver value for I-SEM consumers unless the RO is loss-making for the holder.

With regard to measuring performance of a provider under this approach, it seems that significant complexity, effort and cost would be required to identify the appropriate allocation of flows to a party (the cross border RO holder) that will have only had a marginal role in influencing the flows. By the time the interconnector and generator have been de-rated the RO will be for a relatively small MW amount i.e. actions of the RO holder will not have a significant effect on scheduling interconnector flows which will be determined by the entire market responding to pricing signals.

We do not have a strong view on the 3 approaches for allocation of intraday and balancing market trades. The ‘as traded’ option does not seem reasonable as the non I-SEM provider cannot ensure that its trades are matched cross border. The ‘net pro rata’ approach seems most likely to give an accurate allocation. On the other hand, settling all against the Balancing Market price would be most straightforward and may incentivise participation at day ahead to avoid this exposure so, on balance, this would be the preferred approach.

<u>F) If there is a preference for the “Hybrid” approach:</u>

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

Please provide a rationale for all of your responses.

The Hybrid approach is an interesting idea and is conceptually more acceptable than either the FTR or provider led options as it more appropriately allocates risk of non-performance. However, the issues raised with the provider/FTR led options are still relevant here. In addition, under this option the non I-SEM provider will receive a lower option fee than under the provider led options. This exacerbates the question of whether the action of a cross border RO holder have any significant effect on scheduling interconnector flows. Because they will receive a smaller option fee it is questionable whether this provides any incentive to change their behaviour in their local market. It is certainly unlikely to be sufficient to stimulate investment in new plant.

With regards to the first of the two questions above, it is quite a difficult choice. As stated throughout, a cross border participant does not control interconnector flows so it could be considered unreasonable to penalise them on a delivery based approach. On the other hand, if they are only concerned with availability they may be rewarded when no electricity is being provided to I-SEM (we recognise that this could also be argued against the interconnector led availability based approach but at least in that case the RO option fee is offsetting costs that would otherwise be borne by I-SEM consumers).

It is not appropriate to oblige an asset that is underwritten by consumers to accept risks that are mainly for the benefit of overseas generation. Interconnector participation should be either voluntary or not 'at risk'. A mandated approach combined with proposals set out under question A would deliver this.

SECONDARY TRADING

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

Yes, we agree that direct secondary trading of ROs should be permitted since creation of a market for ROs will:

- allow plant to trade ROs to cover exposure due to planned or forced outages; and
- facilitate exit of uneconomic plant by transferring the obligation to make difference payments.

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

If a simple, minimal centralised system could be established at low cost then this would be desirable as the ability to post buyer and seller offers could improve liquidity in the secondary market. This would allow any RO holder to identify and sell to another pre-qualified entity and the two parties to register the transfer with the RO counterparty.

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

Yes. Since this "back-to-back" trading is effectively a financial instrument, we have doubts that it can be disallowed.

D) 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;

We expect the volume may not justify a centralised trading platform, though on a smaller scale a centralised bulletin board carrying buyer and seller offers would assist the market.

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?

Yes, we suggest that providers should be permitted to acquire RO volume up to nameplate/maximum export capacity. As plant approaches delivery it will have greater certainty about planned outages so that it will be able to deliver with more certainty its full capacity. In any case it would be a commercial decision for the capacity provider to accept the greater risk/obligations that come with increased RO volumes.

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?

Ultimately, secondary trades should be permitted at any time. Should an RO holder encounter challenges early after the auction it could be optimal to trade the RO to another party, thereby improving the likelihood of delivery of the capacity. Similar logic applies during the delivery period - trading could improve longer term delivery against an RO acquired by a now struggling plant.

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?

It would likely assist the market if the pool of pre-qualified participants in a position to purchase ROs in the secondary market was not restricted to those who pre-qualified ahead of the auction. Therefore we suggest that pre-qualification throughout the year would be advantageous. With low volumes of ad-hoc applications anticipated the administrative burden should be small and therefore the turnaround time should not significantly exceed that in the pre-qualification window pre-auction. If the pre-qualification of participants lasted for (say) a year, it would be possible for CRM participants to pre-qualify for an annual auction not just in the window before the auction, thereby smoothing the administrative burden through the year. (We would still expect a deadline for pre-qualification before the auction.)

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

A secondary acquirer of an RO should start from a zero position against each “stop loss” limit. In this way the secondary acquirer of an RO retains the full incentive to deliver the capacity. This is the approach used proposed in the GB market design - to ‘ensure that the same penalties were incurred for a provider holding an obligation for a single day as though it were holding that obligation for a year’. On the other hand, if the stop-loss account does transfer then the acquirer would have limited incentive to perform.

DETAILED RELIABILITY OPTION DESIGN

Reliability option contract length questions

A) 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?

Yes. The objective of the capacity mechanism is to ensure that (alongside SRMC pricing and DS3 revenues) adequate revenue is available to secure investment in plant. Clearly plant requiring greater investment requires the investment signal provided by longer term ROs.

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

For existing plant rolling one year options seem to be appropriate and it is in line with the arrangements in the interconnected GB market.

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?

We suggest that there is a case for medium-term ROs (longer than one year but less than for new plant) for plant that would benefit from additional investment to ensure its viability. Such investment would need to be both significant and clearly above the level of routine maintenance, likely involving significant outage, but it would be lower and shorter-term than for new build.

For example, a plant faced with new emissions control legislation might need to invest heavily in new emissions control apparatus in order to remain operational. That investment might only become viable if the certainty of a longer than one year RO was available. Without the longer RO, the plant would close.

B) 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”?

We prefer option 1, the cost threshold, since it is the simplest approach, least susceptible to different interpretations and lowest cost to implement.

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.

New, upgrade, existing is probably sufficiently granular.

C) 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?

We suggest that for new build fifteen years (as in GB) is probably the maximum to consider in I-SEM. Flexibility might indicate a shorter period, perhaps as short as ten years, but this would come at a premium. We note the extract from the GB impact assessment on financing and agree that fifteen years would significantly reduce financing risk.

For upgraded plant we suggest three years, depending on the definition of this category.

Again, equivalent periods to those in the GB market would be advantageous in levelling the market.

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

We consider that the Technology Specific Life framework is most appropriate. This approach acknowledges that there will always be a mix of technologies providing capacity on the system and avoids a one size fits all approach. While there might be additional work in assessing technologies and determining RO lengths, this should be returned through efficiencies in RO awards, so that shorter lifetime plant is not supported beyond its economic life and longer lifetime plant can be adequately compensated for its longer term delivery.

We consider that 'balanced' economic life is the most appropriate option. The balanced model provides a period of certainty over which to recoup an initial investment and permits participation in annual auctions thereafter. Failure to win ROs in the annual auctions would provide an exit signal, but the plant could also bid for refurbishment ROs earlier than if a longer generic economic life RO has been won in the first instance.

Stop-loss limits questions

D) 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?

On balance, yes, because we feel that alignment with the electricity year outweighs the advantage of having the period with likely the most option calls at the end of the year. The CRM year should be aligned with the DS3 year.

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

We believe that a per month limit has value as the absence of any shorter caps than annual will reduce availability incentives once the cap is reached, which is not in the market's interest. Consideration should be given to alignment with the GB model. (In the GB capacity market penalties are capped at 200% of monthly capacity income and 100% of annual capacity income.)

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

If a per day limit is established, we favour definition as any settlement day, primarily for reasons of clarity and simplicity.

A per event definition is much harder to define, since a series of events might or might not be related by different factors. For example, scarcity in the winter might occur during a month of low temperatures, a week of minimal wind generation and three days of conventional plant outage. Each of these factors has contributed to the periods of scarcity but none of them on their own have caused each scarcity event, so it is non-trivial to define the event.

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

Again, we suggest the levels applied in GB as a starting position. That is a monthly limit at 200% of monthly income and an annual limit equal to 100% of annual income.

LEVEL OF ADMINISTERED SCARCITY PRICE

A) 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

We have no strong view here as we do not expect or believe that interconnector owners should be exposed to FSAP. In any case, we would tend to expect that one of the lower options is preferable as they should be sufficiently high to elicit a market response without potentially exposing participants to excessive difference payments.

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

Yes, we agree that the first three Eirgrid red alerts (not the prediction of failure) provide a reasonable definition of load shedding for the purpose of application of FASP.

C) 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.

We agree in principle that the ability to conduct virtual bidding removes incentives to withhold power from the DAM. In practice however it might be considered administratively simpler to withhold power from the DAM rather than take the additional steps required for virtual bidding. We agree that this effect applies regardless of market power controls in DAM, IDM and BM bids and regardless of the level of FASP.

D) 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.

If the enduring level of FASP is to be introduced after an introductory period, it should preferably be introduced in time for the first four year-ahead delivery year, so that the enduring FASP is in place with the enduring RO arrangements.

E) 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.

n/a

F) 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?

Setting ASP as stepwise linear functions of remaining operating reserve appears to be appropriate.

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

Since the level of FASP is likely to be very much higher than the non-ASP balancing market price, we suggest a low percentage for X, say 20%, so that the initial ASP presents a significant price event to the market which could respond before the a price approaching full ASP is set, the aim being for the market response to avoid full ASP.

H) 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?

Yes, the ASP function should be set in advance of the T-1 auction, so that bidders can submit fully-informed bids in the auction.

I) 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 do not suggest any changes.

TRANSITIONAL ISSUES

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

We would suggest annual auctions would be preferable to a block auction as committing to a four year block up front seems like an excessive commitment for participants with a new capacity mechanism.

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

If the do-nothing approach is adopted, a relatively low level of administered scarcity pricing might be appropriate, but the level should be increased over the four year period so that the enduring level is reached for the normal capacity years (2021/22 onwards).

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

We do not raise any other transitional issues.

GENERAL REMARKS ON MARKET COUPLING

Efficiency of market coupling, a principle which underpins the I-SEM design, will depend on the design of markets on each side of the interconnectors – the more closely the designs of the markets align, the more efficient use will be made of interconnection. When the electricity market is divided into energy, capacity and system services revenue components, the opportunity for divergent design decisions increases. For this reason to ensure optimal use of the interconnectors each revenue component should be aligned as closely as possible with the interconnected market.

While we offer no comment here on the strategic or operational effectiveness of GB market designs, it is clear that market coupling can be most efficiently achieved through approaches matching or resembling the GB designs. Therefore where there are not clear reasons to adopt other I-SEM specific approaches, adoption of equivalent arrangements to those in GB will ensure maximum efficiency of market coupling. We have referred to this in a number of responses to specific questions.