I-SEM

Capacity Remuneration Mechanism, Parameters

SEM-16-073

If you have any questions in relation to our response, please don't hesitate to contact Connor Powell (connor.powell@sse.com)

Response/**December 2016**

Executive Summary

Thank you for giving SSE the opportunity to comment on the SEM Committee's supplementary consultation on parameters under the new I-SEM CRM. SSE has over 1700MW of operational generation capacity and 800,000 retail customers in the all-island market.

The long-term priority for our businesses is delivering sustainable, flexible, affordable energy production to our customers through a diverse portfolio of assets. A stable, well designed capacity remuneration mechanism is a critical component of I-SEM design, providing a predictable revenue stream for generators and a hedge for suppliers.

Comments on Parameter Options

We have provided our comments on the various parameters in a table, with our preferred solution highlighted in blue. The CRM should create strong availability signals for contracted plant, but these should be balanced against operational or cash flow impacts on suppliers (and ultimately customers).

There is little benefit creating a robust customer hedge underpinned by strong availability signals if it has been achieved at the expense of efficient working capital requirements and risk exposure limits for the market as a whole.

Area	SEM Committee Options	SSE Comment
Administrative Scarcity Pricing Parameters		
Shape and Slope of ASP Function	***Option 1:*** *Simple linear function. This option would introduce the ASP at a relatively low level, consistent with a transitional approach to implementing ASP.*	This is a more predictable signal for market participants to manage, without weakening real-time signals for availability. All units will try to ensure that they are available in any period in which prices are expected to rise above the strike price because their expected earnings/penalties will be far in excess of their short run marginal cost[1]. If these signals are demonstrated to be insufficient, a function approximating LoLP v VOLL can be introduced at a later point.
	Option 2: *A LoLP x VoLL approximation. In this option, the ASP would be a simple two-piece linear function, which would be a*	While the SEM Committee argues that this is more cost reflective, we would note that this option is still calculating a theoretical rather than actual balancing energy price[2]. The jump between the strike and ASP price is substantial

[1] With the potential exception of some DSU units

[2] It is ultimately charging participants for a theoretical future loss of load (i.e. a risk based on probability rather than a direct cost)

	reasonable approximation of the value of the product of the Loss of load Probability and the FASP.	and, given structural market concentration, may create perverse incentives to trigger the reserve pricing function for participants with a portfolio of contracted and uncontracted plant. Option 2 can be considered in future if availability signals under a simple linear function are shown to be insufficient.
Cost Recovery and Charging		
Cost Recovery and Charging	***Option 1****: A highly focused Supplier Charging Base focusing Supplier charges on the peak period (5pm to 9pm) in Winter quarters*	As noted in the consultation, peak demand is becoming less and less important as a driver of scarcity. Given the reducing correlation between peak demand and scarcity and the cash flow issues this option presents for suppliers, we do not think this is a viable solution. As shown in GB in the last two years, many scarcity periods now take place outside 'winter'.
	Option 2: *A focused Supplier Charging Base, with Supplier charges focused on the period 5pm to 9pm throughout the year*	These periods still correspond to peak demand (primarily driven by domestic peak demand). This could lead to perverse incentives for suppliers to target particular customer types. As demand is becoming less important as a driver of scarcity, we do not think this is an attractive solution.
	Option 3: *A broader based Supplier Charge, with Supplier charges focused on a broader day-time period from 7am to 11pm in all quarters.*	These time periods capture any potential scarcity event but are *future proof* in that they are robust to a further breakdown in the correlation between scarcity and peak demand as wind builds out and conventional plant capacity margins tighten post I-SEM go-live. We agree with the SEM Committee's minded-to position to favour Option 3.
Interest Rates on Socialisation Fund Balances	*We seek feedback on which LIBOR (or other such reference rate) should be used as the BIR, and on values of the SPR and DPR.*	ICE LIBOR can provide an appropriate Base Interest Rate – the reference rate should reflect the T&SC in that the tenor should be close to the period of time in which a deficit or surplus can persist or be corrected.
Reliability Option Parameters		

DSU Floor Price	*On the basis of the above analysis,* ***the SEM Committee sees a DSU floor value of €500/MWh*** *as striking an appropriate balance between objectives.*	We strongly agree with the SEM Committee minded-to position. €500/MWh strikes the appropriate balance between facilitating the contribution of DSUs and providing a robust availability signal/supplier hedge. To incorporate shut down costs to a greater extent would substantially reduce the value of the supplier hedge with no corresponding increase in system reliability[3,4].
Carbon Intensity Factors and Transport Adders	*In the case of natural gas, it is highly likely that the natural gas price index will be a GB NBP reference.*	GB NBP flows have been substantially lower with the commissioning of a new RoI entry point. We do not understand why the RAs cannot request a carbon intensity figure from GNI as a better approximation of the actual carbon intensity of gas burned within power stations on the island.
	The Directed Contract process uses a Low Sulphur Fuel Oil 1.0% FOB North West Europe Swap as the reference fuel index for Fuel Oil.	We do not understand why the CRM Delivery Body (TSO) should select a fuel index – this is outside of their expertise and could be considered a potential conflict, given that the index could determine how plant contracted by the TSO will need to perform in some periods.
	The SEM Committee intends to make the final decision on CIG and CIO alongside the decision on the reference fuel index.	Again, we do not understand why the CRM Delivery Body (TSO) should select reference fuel indexes – this is outside of their expertise and could be considered a potential conflict, given that the fuel indexes could determine how plant contracted by the TSO under the RO will need to perform in some periods.
	CRM Decision 3 (SEM-16-039) confirmed that the CRM Delivery Body will calculate the fuel transport adders periodically, and submit them to SEM Committee for approval.	CRM Decision 3 did not evidence why the CRM Delivery Body was best placed to calculate fuel transport adders or why this function was a reasonable fit with its other roles as MO and TSO. It is difficult to see why a TSO would be best placed to calculate these as they are based on information that the TSO would not have direct access to.
	The RAs should retain responsibility for the selection of fuel indexes and	

[3] DSUs are not required to provide an absolute price hedge, unlike generators and those sitting above the strike price for a scarcity period would likely contribute towards system reserve

[4] A higher strike price will decrease real-time availability signals for conventional plant as they will only face an opportunity cost rather than an actual cost for non-performance during periods in which prices have risen substantially above their short run marginal cost

	should procure a recommendation on fuel indexes and adders from a consultant with the relevant expertise. There is no clear justification for using the CRM Delivery Body for this function as they lack the relevant information, have no clear synergies between this function and the others it is expected to deliver and will require additional oversight given the potential conflicts between this specific CRM Delivery function and the TSO function.	
Billing Period Stop Loss Limit	*A Billing Period is defined as a week and is used for imbalance and difference payment settlement; and* *A Capacity Period is defined as a month and is used for capacity payment/charge settlement.* *On balance, the SEM Committee remains minded to set the Billing Period multiple as 0.5x the annual stop loss limit (i.e. 0.75 times the Annual Option fee)*	We (and many other market participants) had assumed that the SEM-15-104 consultation and SEM-16-022 decision had been considering monthly caps rather than the balancing market billing period[5] i.e. capacity billing period rather than imbalance billing period, even though the language in the latter decision paper was contradictory. Given that you need two pieces of information to calculate a stop loss limit (the relevant option fee and the capacity billing period over which it is paid), it would be far more straightforward to proceed with a monthly stop loss limit. **Weekly stop loss limits have never been consulted on at any point by the SEM Committee and their introduction at this point is a radical departure from market expectations of a monthly stop loss limit.** Stop loss limits linked to weekly imbalance billing periods introduce an extreme level of availability risk and are likely to result in arbitrary and unnecessary solvency and cash flow issues for generators. These create real and unnecessary costs[6] without really making any real change to the underlying availability incentive for generators. The SEM Committee should revert to their **actual** prior minded-to position i.e. that a generator should expect to lose up to ***9 times the relevant option fee***[7] over a capacity billing period of 1 month. This ensures that there is a

[5] The language in SEM-16-022 decision was confused on this point, it stated that a ***billing period is defined as the period between the physical delivery of electricity and the time at which ISEM payments will occur*** before giving a different calculation based on the monthly capacity billing calculation "***e.g. for a billing period of one month this will be 9 times the relevant option fee".***

[6] Generators will need to be able to support a much higher VaR figure and will potentially need to post far more collateral across the markets

[7] As stated in SEM-16-022

		very strong availability signal retained for capacity[8] without creating substantial uncertainty[9] over CRM earnings that could be priced into offers once capacity margins tighten.
New Build, Termination Fees and Performance Bonds		
New Capacity Investment Rate Threshold	*Setting the New Capacity Investment Rate Threshold at around 50% of the BNE gross investment cost would result with a threshold broadly in line with international norms. On this basis, the value would be approximately €310/kW of derated capacity, if this approach had hypothetically been applied in 2016.*	As noted in the paper: *The threshold should serve as a reasonable proxy for the financial commitment incurred for new build capacity, **but should not penalise investors who are able to build efficiently at low capital cost, including re-using existing infrastructure.*** The threshold needs to distinguish between minor and major refurbishment but should not exclude refurbishment that makes economic sense. We think that the % of gross BNE investment costs selected (50%) is too high given that the BNE reflects just one technology type and may preclude some new build technologies from receiving a long term contract. We would suggest a lower percentage of gross BNE costs is selected (40%) that more closely matches the ISO NE benchmark given the tenor of the I-SEM contracts are more comparable to ISO NE than GB.
Termination Fees for New Build Capacity	• *Termination at any time after the auction but more than 13 months before the start of the Capacity Year: €10/kW.* • *Termination between 13 months before the start of the Capacity Year and the*	We agree with the minded-to positions outlined by the SEM Committee – they strike the correct balance between maintaining incentives for developers to bring forward projects, without providing for speculative bidding for capacity contracts that cannot be delivered. As noted in the response, the initial penalty fees in GB could be seen to be a contributing factor

[8] Assuming a low capacity clearing price of €25/kW, a generator can still reach their monthly cap during two ASP events

[9] Using the imbalance rather than capacity billing period creates an unnecessarily extreme level of risk that can only be managed through my offers. If we assume a generator faces a two week period of forced unavailability at an unknown period with no secondary capacity trades available, this would change my expectations for CRM earnings from a range of **€10m to €2.5m** to a range between **€10m and -€5m**.

	start of the Capacity Year: €30/kW; *• Termination after the start of the Capacity Year: €40/kW.* *For the first transitional auction, given the proposed timings, any New Build winner would immediately be subject to a termination fee of at least €30/kW.*	to a new build project failing to reach financial commitment by the initial milestone and then by an extended milestone date. The proposed termination fees for the I-SEM CRM appear to be appropriate mitigation against similar issues in Ireland.
Termination Fees for other Capacity	*Should these classes of bidder be required to pay termination fees, since the risk that they fail to deliver is not necessarily related to the New Build criteria set out in the CMC? Clearly the impact on customers if they fail to deliver is the same, but arguably the delivery risk is lower.*	While the Grid Code has been referenced in the consultation, we believe that this will need to be changed given the short notice period licensees may receive between a T-1 auction and the exit signal generated. As noted in the consultation paper – there are clear incentives for existing capacity to honour Reliability Option contracts. The SEM Committee should bear in mind that licenced generators would effectively need to become insolvent in order to avoid their obligations. While we recognise that existing generators with a single plant may have limited 'skin in the game', insolvency is not an option that will be exercised lightly, nor will it be invisible to the market, given ongoing obligations under the T&SC to post collateral. Any termination fee and associated performance bond for existing capacity would over collateralise the market, given that these assets are already built, are being maintained and are posting credit in order to participate in the market. The CRM must be technology neutral and should not distinguish between existing capacity and DSUs, but should distinguish between unproven and proven capacity. Given the HLD decision to physically back reliability options, termination fees should be considered

		for any capacity which is unproven.
Auction Parameters		
Auction Price Cap	*An adjustment to outage assumption for infra-marginal rent may be appropriate to align the assumptions with the de-rating decisions* *Adjustments to reflect the introduction of ASP, combined with the Reliability Option, which will have a number of effects on the infra-marginal rent (IMR) that a BNE plant can earn* *To adjust from nameplate capacity to de-rated capacity. The SEM Net CONE is implicitly expressed in €/kW of nameplate capacity, and Reliability Options will be paid per unit of de-rated capacity* *The SEM Committee favours setting the multiple at the lower end of this range (1.5x Net CONE).*	We would agree that the de-rating decisions should align with the BNE calculation as well as the conversion from nameplate to de-rated capacity. We also agree with the methodology used to recalculate IMR following the introduction of a Reliability Option. The application of partial ASP presupposes a decision on the ASP function under consultation within the parameters paper and it is not consistent with the theoretical IMR earnings for a new entrant plant. A 1.5x multiple for Net CONE appears to be appropriate – this can always be reviewed at a later stage if the price cap is restricting entry.
Existing Capacity Price Cap	*The definition of fixed operating costs does not include any element to cover sunk costs investment costs - depreciation or return on capital.* *There is currently significantly more operational capacity than Capacity Requirement and most of this capacity has*	A number of the principles outlined within the paper are not consistent with the solvency of a licensee. The Regulatory Authorities must have regard to the ability of a licensee to finance their activities, we cannot see how the minded-to positions to disallow elements of financing costs or depreciation or elements of reported financial information align with these requirements. As stated previously, a Grid Code obligation to maintain plant in an insolvent legal entity is not consistent with other regulatory obligations,

	to give 36-months' notice of its intention to close. *The SEM Committee may also undertake some adjustments to reported data, where for instance, it is of the view that cost allocations between units are not appropriate, or that the reported results are not consistent with efficient operation of the assets in question.*	therefore the assumption that plant must continue to give 36 months' notice of intention to close is flawed. We are particularly concerned by the statement with regard to efficient operation – generation assets are not regulated assets with a guaranteed return on investment. Disallowing costs or introducing efficiency factors as would be applied under a network price control is entirely inappropriate given the lack of certainty with regards to revenue or future costs[10]. At this level of detail, the RAs would be straying into operational decision making on behalf of licenced asset owners.
	SSE believes that a simple 0.5 multiple of Net CONE is an appropriate Existing Capacity Price Cap. Introducing concepts like efficiency savings or disallowable costs is entirely inappropriate given that: • Generation assets are not regulated assets and have no guarantee over future revenues; • Decisions on efficient costs would effectively place some responsibility for operational decision making on the RAs rather than the asset owner; • A tighter cap for existing capacity will only increase the number of exceptions for the RAs to review; • Increasing the difference between the existing capacity price cap and the price cap for new build will bias the auction in favour of more expensive new build capacity. New build capacity is inherently more expensive than existing capacity and the tighter price cap will simply increase costs to end consumers by unnecessarily accelerating the investment cycle for I-SEM generation plant. As noted within the paper, there is a significant short-term surplus of capacity and substantial incentives for generators to compete costs down to (or below) break-even. Further intervention appears unnecessary – parameters can always be adjusted following the first auctions.	
Demand Curve Parameters	*The SEM Committee is considering:* *Setting the demand curve for the first transitional auction horizontal at the*	We agree with the proposed parameters for the transitional auction – 8 hours is the minimum acceptable Reliability Standard and procurement below this level would create harmonisation issues with other CRMs that

[10] Would a disputed GPI be considered an inefficient cost? Or would the maintenance or refurbishment required to correct Grid Code Compliance be considered an inefficient cost?

	Auction Price Cap between 0MW and the 2020/21 Capacity Requirement as estimated prior to the first transitional auction; and *Making the demand curve pass through point X where the price = Net CONE and quantity equals the Capacity Requirement, analogous to the price and volume which determine the Annual Capacity Payment sum in the SEM CPM.* *Making the demand curve vertical between the Auction Price Cap and Net CONE, at a level of MW consistent with the Capacity Requirement*	typically apply a 3 hour LOLE. There is no risk that the auction could clear above the existing CRM given the capacity surplus on the system and with an existing capacity price cap set at a 0.X multiple of Net CONE. It therefore seems appropriate to apply Net CONE at the Capacity Requirement for the transitional auctions. **Given the nature of the transitional auctions, we believe that Option A is most appropriate**. This maintains the options associated with existing capacity for the T-4 auction without providing for plant seeking exemptions to the existing capacity price cap. Both Option B and C will result in a more radical level of plant exit creating a potentially unnecessary entry signal for plant in the T-4 auction. Option A is more likely to give a least cost outcome for customers over the transitional period to the first delivery year for the T-4 auction.
Locational Parameters	*[T]he SEM Committee does not propose at this stage to include the additional complexity of defining local demand curves.*	We agree – local demand curves add unnecessary complexity and should not be considered as part of the I-SEM CRM.
Load Following		
Load Following Parameters	*The granularity of these factors would be monthly and time of day.*	We agree with the approach outlined – it should lend itself to more straightforward standardisation and trade capture of instruments to trade forward power and secondary capacity. While more complexity might free up additional de-rated capacity, this benefit should be balanced against the difficulty incorporating these into systems and products. Given that load following parameters should be fairly consistent across years; we believe that parameters should be applied to subsequent years without adjustment to allow generators to better plan outages.