I-SEM

CRM Detailed Design

If you have any questions in relation to our response, please don't hesitate to contact me at connor.powell@sse.com

Summary

Thank you for giving SSE the opportunity to comment on the detailed design of the I-SEM Capacity Remuneration Mechanism (CRM). SSE is a utility with customers and assets in both Ireland and Great Britain – we have operated under a number of different electricity trading and transmission arrangements. To secure energy for its Irish customers, SSE is involved in energy portfolio management, electricity generation and gas production. We have tried to reflect this experience in our response.

Our long-term priority for the businesses in our Wholesale segment is sustainability in energy production through a diverse portfolio of assets. Our assets help to keep the lights on by being available to produce energy when required and flexible enough to respond to changes in demand/wind when they occur. As a major investor in and operator of electricity generation capacity in the SEM, SSE depends on a well-designed capacity remuneration mechanism.

Our response covers each of the different design areas detailed in the consultation. The table below details our preferences in each area.

Capacity Requirement	• SSE recommends that the Irish Market move from the desynchronised 8 hour and 4.9 hour LOLE reliability standard **to a regional 3 hour LOLE reliability standard** with a common methodology. • Given the proportion of wind and DSR currently installed on the Irish system, **a de-rated capacity requirement** is the best way to account for plant reliability. • Either a worst case or least regret calculation for **demand forecast uncertainty** would both produce an answer that will meet the defined security standard. • **Interconnectors** are transmission, not generation capacity. • A **single zone auction** for capacity matches the I-SEM design.
Product Design	• An **indexed strike price** that is explicitly linked to a heat rate and a spot input fuel rate hedges capacity providers. • The selection of the **hypothetical reference unit** must be conservative. • The DAM should be selected as the **reference market**. Any other option will have substantial knock-on impacts on price formation and participation across the curve. • A **Load Following Obligation** should be included in the design. • Incentivising **real-time availability** is fundamentally a balancing market design issue. No additive physical penalties

	are required. • **Pre-qualification and pre-commissioning** have major impacts on allocation and pricing. Commitment should be addressed as a key topic in the second consultation.
Eligibility	• **Supported renewable plant** should be eligible to participate to the extent that they are not over-remunerated and that they take on additional financial risk to physically deliver power during periods of scarcity. • If overlapping capacity arrangements for **peat or NI generation** remove incentives to perform, market participants should be able to opt for either a Reliability Option or the retention of their existing capacity agreement. • **Renewables without support** should be free to participate in the auction assuming adequate de-rating for expected reliability. • **Market power concerns** should be addressed through the allocation of supplier hedges rather than through constraining bidding in the auction. • **Mandated prequalification** is achievable – **mandated bidding** will have knock-on consequences. • **Non-firm generation** should be eligible to bid and subject to the same de-rating factors as firm generators of comparable technology. • There is no **DSR disadvantage** inherent in the design of reliability options - demand side participation does not need an additional incentive over and above other forms of capacity. • A **generic de-rating factor** by technology is subject to lower error than plant specific derating. • The central de-rating factor should act as a cap but plant operators should have **discretion to de-rate** to a lower level based on risk appetite. •
Supplier Obligations	• Until HH meters are installed across the market, the current SEM approach to **profiling demand charges** should be applied. • Matching payments to the trading periods in which the payments arise is preferable, but this decision should take account of constraints on the operation of a state-owned imbalance settlement agent. • The consultation paper states that netting may take place between option fees and difference payments but energy market exposure should also be incorporated too. • Given the dual currency nature of I-SEM it is appropriate that exchange cost variations are recovered by market operators

	through a socialised charge.
Governance	• The choice of whether to adopt counterparty contracts or capacity agreements should be **dictated first of all by accounting issues.** • Without a single counterparty body available to take on the liabilities created by allocated reliability options this could potentially have damaging impacts on the **ability of licence holders to finance their activities.** • The TSO, EirGrid Group has some **clear conflicts of interest** as the likely imbalance settlement agent, delivery body, interconnection asset owner and interconnection asset developer. These should be managed through the Roles and Responsibilities workstream.

Capacity Requirement

Loss of Load Expectation

The security standard is central to the success of any CRM – a minded-to position must therefore be clear, consistent and coherent as to why a particular LOLE. The draft paper[1] published alongside this consultation gives some clear recommendations as to why the existing SEM reliability standard should be adjusted to 3 hours LOLE:

"As Ireland and Northern Ireland are already using similar assessment methodologies to those used in Great Britain and France, applying a coordinated regional generation adequacy standard is arguably a prudent next step."

"This coordinated regional approach may facilitate greater cross-border participation in generation capacity markets and lead ultimately to a regional generation capacity market."

"The quality of electricity supply is an important consideration for foreign direct investment."

"Using these different estimations of VOLL, we can calculate the value of 1500MWh of Expected Unserved Energy to be between 16 and 35 million euro. These figures can be compared with the costs in the previous table 2 [between 19.2 and 5.8 million euro]"

This independent analysis appears to have been entirely dismissed by the SEM Committee, on the basis that:

- Unserved load 'might' not have a significant impact on customers.
- The low VOLL figure used in SEM 'might' overestimate the value customers actually place on not being disconnected.

These seem like arguments that are just as theoretical as the theoretical benefits that could be attributed to a reliable electricity system. Likewise, a conservative range for the expected costs of an increase in LOLE have been derived only from the current capacity pot, while the actual outturn figures for a competitive auction for GB capacity have been dismissed.

The SEM Committee does not appear to have any reasoned justification for its minded-to position – we cannot see why the clear advantages of moving to a 3 hour LOLE have not been better outlined and considered within the paper. These are:

- A resolution of the mismatch in internal SEM (RoI and Northern Ireland) capacity arrangements that have already forced SONI to procure additional capacity outside the SEM CRM;
- Harmonised regional capacity arrangements with Great Britain, France, Netherlands and Belgium;

[1] EirGrid (2015), Options for the Capacity Adequacy Standard in the I-SEM

- A modelled range of values for benefits that exceed the modelled range of costs in a clear majority of scenarios;

A very narrow focus on cost seems to have led the SEM Committee away from the option that clearly delivers the most value to I-SEM customers. Unlike the current SEM CRM, the I-SEM CRM will explicitly allocate capacity contracts to individual plant rather than allocate money to all available plants.

Therefore, we would expect the implementation of the SEM Committee minded-to position to be the rapid withdrawal of capacity after the first auction to a level in which loss of load is expected; market power issues are exacerbated[2] and the respective TSOs and Departments inevitably intervene to procure capacity outside of the I-SEM CRM.

SSE would therefore recommend that the Irish Market move from the desynchronised 8 hour and 4.9 hour LOLE reliability standard to an all-island 3 hour LOLE reliability standard.

Accounting for plant unreliability

Setting a requirement for the total nameplate capacity needed to meet a specified reliability standard works in the current SEM CRM, where every plant effectively has a master agreement that allows them to receive a capacity payment when they are available to generate. Value is diluted or concentrated rather than being explicitly allocated to plant[3]. In a CRM in which only certain plant will be eligible for payment, applying the same approach may lead to a situation in which suppliers are effectively only procuring a financial hedge against scarcity rather than physical capacity.

The auction is only distinguishing between capacity by price offered, so there is no way for suppliers to express a preference for reliable rather than unreliable plant. This means that preference has to be expressed earlier – through central de-rating prior to an auction. Given the proportion of wind and DSR currently installed on the Irish system, SSE would recommend that a de-rated requirement is the best way to account for plant reliability.

Accounting for demand forecast uncertainty

While de-rating of supply is likely to account for the greatest source of uncertainty, demand forecasting uncertainty must also be accommodated within the design of the CRM. The paper states that:

"this approach is likely to deliver a Capacity Requirement that will, on average be less than that required to meet the defined security standard."

We would agree – either a worst case or least regret calculation for demand would be a far more robust approach, both are on average likely to produce an answer that will meet the defined security standard.

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[2] Regardless of the product design of Reliability Options, suppliers will face an unhedged exposure in either balancing or day ahead in a system that will have a far lower capacity margin in many more trading periods.
[3] A reliable generator/DSU should receive a more concentrated revenue stream than its unreliable equivalent.

Stochastic modelling approaches are referenced in the paper, but unless they can be clearly understood and replicated by the suppliers relying on the CRM to hedge exposures, we do not believe that they should be used to account for demand uncertainty in the CRM.

Accounting for interconnectors

European legislation and regulations define interconnection as:

- Transmission capacity, rather than generation capacity;
- Subject to market rather than operator determined flow.

Any assessment of interconnection should therefore be based on potential participation of cross-border generation to the extent that it can contribute to meeting the I-SEM reliability standard. An assessment that purely focuses on the technical capacity of interconnection will inevitably overestimate its contribution.

Location

SSE would agree that a multiple zone auction or locational price adjustment would be undesirable and unachievable respectively. An auction that fills a single I-SEM capacity requirement is the only sensible option. Locational price signals that would inform investment and operation cannot be introduced through a capacity auction alone – if this is seen as a major issue, this should be considered through a separate project that covers connection, losses, services, other system charges and network tariffs.

It is interesting that the SEM Committee does not mention the desynchronised reliability standards that apply in Northern Ireland and the Republic of Ireland as a potential contributor to locational issues in the paper. This mismatch has already led to a TSO intervention outside of existing SEM CRM. One simple resolution would be to move to the lower of the two standards that apply to the all-island market – multiple reliability standards for a single capacity zone will always present problems.

Product Design

Strike Price

At the point at which the auction for the allocation of Reliability Options clears, suppliers and generators will be left with two different sets of exposure to hedge:

- **Suppliers** will have a call option that allows them to purchase a quantity of electricity in the given market at the strike price, if prices in the reference market exceed the strike price. Given that the ‘option’ will be out of the money in the majority of trading periods, suppliers will still need to effectively manage their the risk that arises from the mismatch between long-dated forward power supply contracts and short-term contracts for physical delivery of power. This is dynamic and a supplier’s forward portfolio exposure along the curve will remain the most important risk to manage, regardless of any cap on exposure in a relevant spot market.

- In exchange for an option fee, **generators** have also effectively sold a put obligation on physical delivery of their power in the reference market. While they will also need to manage the risk that arises from mismatches between forward exposures and prompt prices, however, most power plants will have access to spot fuel markets and short term transportation capacity.

The exposure created by a put obligation with a fixed strike price that does not track prompt fuel or transportation causes far bigger issues for a generator than a dynamic hedge in a spot reference market causes for suppliers. There is no way for a capacity provider to effectively manage the risk that their marginal costs may move above the fixed strike price without taking on an unnecessary forward exposure for the period which the obligation covers.

SSE believes that:

- An indexed strike price that is explicitly linked to a heat rate and a spot input fuel rate should perfectly hedge capacity providers;
- Picking an actual rather than hypothetical reference unit reintroduces the same risks that were removed by indexing the strike price;
- The selection of the hypothetical reference unit must be conservative – generators will have to price in additional risk if they have to account for their own availability and frequent hours of 'scarcity[4]';
- A variable strike price can be managed by suppliers entering into standard forward contracts[5];
- Volatility in the strike price is a relatively small risk within the context of a supplier's forward portfolio;

These design decisions clearly follow from the primary objective of the reliability option – ensuring the SEM has sufficient capacity to deliver a set reliability standard. The supplier benefits are important but secondary given that these risks can also be managed through well-functioning forward markets.

Reference Market

The consultation states that:

"There are a number of obvious potential choices for the Market Reference Price including each of the proposed I-SEM energy markets."

If we return to the exposures created at the point at which reliability options are allocated to capacity providers and suppliers, we believe that these should be perfectly manageable by a participant that is available to deliver MWh during periods in which scarcity is expected. Of the 4 options considered, only two can actually guarantee that plant performing in real-time do not face penalties – which should be a basic criteria for consideration as a viable option.

[4] Scarcity under a reliability option is explicitly defined by the strike price – setting a parameter that guarantees frequent 'scarcity' doesn't necessarily incentivise availability during periods of actual physical scarcity.
[5] As noted in the consultation paper, these will need to be redrafted to account for the introduction of Reliability Options.

'Basis risk' and *'complexity for generator and supplier hedging strategies'* are identified as downsides for every option that does not use the day-ahead price.

We cannot see why anything other than the day-ahead price is being considered for the market reference price. We summarise the advantages and disadvantages for 100% DAM price below by comparison to the alternatives:

"Price robust and accessible to capacity providers"

- Every other option creates an unknown basis risk for a capacity provider that must be priced into an auction offer and included as a premium within the cleared price of capacity.
- Basis risk can only be managed by option holders withholding capacity from the day-ahead auction during periods of system stress or complex bolt-on settlement rules.

"Promotes efficient day-ahead EUPHEMIA scheduling"

- Every other option will distort market participation during the critical unit commitment period, exacerbating the impact of scarcity on pricing and scheduling.

"Consistent with existing approach to CfDs and likely approach for FTRs"

- Generators and suppliers will create additional unnecessary exposures when they trade standard forward products referenced to the day ahead market. Any solution requires fragmentation of forward energy products i.e. products referenced to multiple market timeframes.
- Under other options, cross-border participation in the CRM will be limited to TSO-TSO countertrades as there is no standard balancing product that would provide access for non-SEM generation.

"Weaker than BM or IDM at incentivising availability at times of system stress"

- It is not clear why capacity providers who have committed to physically deliver power in the DAM are not exposed to the availability incentives implicit in balancing anyway.

"Would not provide hedge for scarcity prices if implemented in BM"

- Regardless of the outturn price, suppliers are significantly more exposed to scarcity being present in DA pricing due to the relative volumes that flow through the two different market timeframes.

SSE would strongly recommend that the DA price is selected as the reference market. Any other option will have substantial knock-on impacts on price formation and participation across the curve. Availability incentives are implicit through balance responsibility – participants that fail to physically deliver power will have to purchase power from the system at a premium that reflects scarcity, but scarcity as defined in the consultation paper will also be apparent at the day-ahead stage too, as can be seen in the comparison of ex-ante SEM and GB balancing prices. Balancing market design is the place to consider incentives/penalties for availability and flexibility, including administered scarcity pricing. Reliability options are about system reliability – hence they should be referenced to the day-ahead market.

Load Following Obligation

Given that reliability options carry large tail risks, they will inevitably be relatively illiquid instruments. Secondary trading may take place during summer, but this cannot be assumed given market concentration. A load following obligation is a simple solution. It hedges capacity providers and purchasers above the strike price – this is more likely to result in sufficient 'in-the-money' capacity on the system who can accurately reflect their costs in the capacity auction or day-to-day trading outside peak-demand periods. **SSE would recommend that an LFO is included in the design.**

Physical Performance Incentives

While we recognise the RAs concern about ensuring that availability is adequately incentivised in I-SEM, this is fundamentally a balancing market design issue. Balance responsibility means that any participant that has committed to deliver or consume power is subject to an exposure to the extent that they have under or over committed.

The paper notes that US and Colombia markets have struggled with availability, this is primarily a result of regulatory constraints and lack of consideration of gas/electricity interactions[6] – whether explicit bidding controls or RO strike prices that fail to allow for changes in fuel price/availability. While the paper states that:

"The information that we have collected from US and GB markets suggests that additional incentives could be effective in incentivising physical performance."

It is difficult to see any evidence from GB (given that cash-out reform has not taken effect and the delivery year for the capacity auction is 2018/19) and impossible to analyse the impact of ISO-NE's performance incentives given that they were only approved by FERC[7] on the 30th May 2014 and have not yet been implemented in other ISOs. The RAs are citing theoretical rather than observed benefits.

Scarcity and flexibility pricing can be addressed through the Balancing Market in the Energy Trading Arrangements workstream – there is no need to incorporate three sets of administered pricing[8] into one market – it creates overlapping and non-identical incentives and exposures for supply and demand that are unnecessarily difficult to manage. **Real-time availability presents one simple problem – how do I ensure committed plant delivers in real-time? – it only requires one simple solution, well designed imbalance arrangements.**

Pre-commissioning and pre-qualification penalties

Accurate information on pre-commissioning and pre-qualification is important, as has been demonstrated repeatedly in auctions to allocate contracts for capacity. In the finalised GB CfD and capacity arrangements there are already multiple examples in which new investment or existing capacity have changed their commitment decision once contracts were allocated, with a substantial impact on auction outturns:

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[6] Availability of firm gas capacity has been a major issue within US systems.
[7] R14-1050-000; EL14-52-000
[8] Regulated DS3 tariffs, RO performance incentives, PAR1 imbalance, Administered Balancing Prices

- Some opt-out decisions in the GB capacity auction which were flagged as remaining open for the delivery year have now announced their closure.
- Solar PV contracts were awarded to generators at a price far below commercial viability.

Procuring capacity on the basis of uncertain forecasts of physical conditions is difficult – if the information provided by new and existing units at the point of commitment is not accurate, this becomes impossible. Particularly for participants without existing generation, inadequate pre-commissioning and prequalification conditions allow participants to bid for options without expectation of delivery. Given the impact this can have on allocation and pricing, this should be a key topic in the second consultation.

Eligibility

Renewable support mechanisms

Whether supported renewable plant can participate in the auction is primarily an allocational issue. Both the existing REFIT and CfD schemes could allow for renewable generators to participate assuming that a sensible reference market is chosen. The consultation notes that:

"Making existing REFIT generators ineligible is unlikely significant change their net income or have a material effect on customer bills but it will change whether this money is recovered from all-island market mechanisms or from the Public Service Obligation (PSO) Fund in Ireland."

You can make a similar statement in relation to CfD supported plant in Northern Ireland. Given that one of the key aims for the Energy Union is to better integrate renewables into energy markets, SSE believes that supported renewable plant should be eligible to participate to the extent that they take on additional financial risk to physically deliver power during periods of scarcity.

PSO backed Peat and GUAs

The PSO backed contracts and Northern Ireland GUAs are slightly different in that the contracts blunt any reliability incentives[9]. If overlapping capacity arrangements remove incentives to perform, we would suggest that market participants that have these long-term contracts are able to opt for either a Reliability Option or the retention of their existing capacity agreement[10].

The decision paper should also outline the SEM Committee's position on the capacity competition contracts[11] allocated to Aughinish and Tynagh in 2003. Given that these projects have already been notified and received State Aid clearance from the European Commission in decision N 475/2003 they should be treated consistently with the other State Aid notified

[9] While both the GUAs and PSO agreements have availability elements to them they are separate to the performance incentives under a reliability option.
[10] This is the approach that has been taken for long term STOR contracts in GB.
[11] Known as the Capacity and Differences Agreement (CADA)

plant covered under renewable support and other PSO mechanisms detailed in the consultation.

Longer term ancillary services contracts

DS3 contracts will provide a marginal rather than central revenue source so should not impact eligibility for the reliability options. However the consultation paper is correct in noting that the DS3 and CRM auction processes should be aligned, particularly with regard to timing and the treatment of locational issues.

Renewables without support

Renewables without support should be free to participate in the auction assuming adequate de-rating for expected reliability.

Mandatory vs Discretionary Bidding

There are concentration issues in the Irish generation market – however mandatory bidding isn't necessarily the best way to address these. The paper makes a comparison between GB and Ireland:

"In GB, existing capacity was required to explain any capacity withdrawal of existing plant – and needed to justify non-bidding in terms of the plant being retired before the end of the delivery year."

This cannot be characterised as a mandatory bidding, but more mandatory pre-qualification for existing capacity, to ensure that the TSO has an accurate picture of system conditions at the point at which it holds the auction. We would agree with mandatory pre-qualification but not mandatory participation. The GB wholesale market is not concentrated – the rules on pre-qualification were designed to avoid gaming rather than explicitly designed to target the exercise of market power.

SSE would suggest that market power concerns should be addressed through the allocation of supplier hedges rather than through constraining bidding in the auction. While a regulator can mandate that a plant must participate, it is more difficult to mandate how that plant must participate without unintended consequences.

Treatment of generation with non-firm transmission access

There is no connection policy in place for new conventional plant in RoI – making non-firm plant ineligible to participate in the I-SEM CRM would effectively be acting to close off access for new entrants to the Irish market. No new generation would be able to pre-qualify for delivery of firm generation capacity in advance of delivery of transmission access (typically 2 to 3 years after a plant is commissioned).

Given that the existing SEM does not distinguish between firm and non-firm availability and the only coherent choice for a reference market does not take into account definitions of transmission access, we cannot see why the RAs would wish to change the SEM definition to discriminate against new entrants. Non-firm generators will have to account for their access when bidding but the option to participate on an equal basis with existing generation capacity should be a given. SSE believes that non-firm generation should be eligible to bid and subject to the same de-rating factors as firm generators of comparable technology.

Demand Side Participation

The current SEM CRM has incentivised a substantial amount of DSU participation – the technology can be considered relatively mature. At the point at which I-SEM goes live in Q4 2017, DSUs should be in a position to participate on equal terms to regular generators/suppliers. The paper states that:

"It has been argued that unless specific new provisions are included to accommodate DSUs, DSUs will be a disadvantage relative to generators."

We cannot see what disadvantage is inherent in the design of reliability options or why demand side participation needs an additional incentive over and above the avoided energy payment. This is a negative equivalent to the strike price capped energy payment a generator would receive during a period of system stress. The reliability option effectively doesn't distinguish between generators (who have input costs that reflect their cost of producing energy) and DSUs (who have input costs that reflect their cost of consuming energy).

SSE would be concerned that both Option 2 and Option 3 effectively increase the compensation DSUs receive for their contribution to reliability while reducing their risk exposure. This could endanger the state aid application for the CRM as a whole as it risks overpayment of a specific type of capacity provider.

One actual concern that does not appear to have been addressed is mirroring the risk mitigation a load following obligation provides for generation – a simple means of doing so could be to limit the hours contracted under reliability option contracts for demand to periods in which scarcity is expected.

Derating

We agree with the majority of RA minded to positions on de-rating:

- A generic de-rating factor by technology is subject to lower error than plant specific derating;
- The central de-rating factor should act as a cap but plant operators should have discretion to de-rate to a lower level based on risk appetite;
- Historical data is more reliable than future expectations of availability[12];
- Assessments of marginal capacity contribution better fit the Irish system than average capacity contribution;

[12] The example of the contribution from interconnectors in the GCAS is flawed – these availability figures appear to be based on market expectations rather than technical expectations.

- Grandfathering is not a concept that should be applied to de-rating – the TSO needs to know the contribution units could make to reliability rather than the economic signal a unit may need[13].

Prequalification

As stated earlier in our consultation response, a robust pre-qualification is a key design area – procuring capacity on the basis of uncertain forecasts of physical conditions is difficult – if the information provided by new and existing units at the point of commitment is not accurate, this becomes impossible.

The pre-qualification criteria listed in table 4-4 give a reasonable outline of standards that new and refurbishing plant should meet in order to participate[14]. The final decision should include robust standards in relation to financial commitment to ensure that capacity providers that fail to progress through key delivery milestones do not 'block' the allocation of capacity agreements to plant that will actually make a contribution to the reliability standard in the delivery year.

Defining a clear decision and appeal process for pre-qualification is important – we would prefer a process that includes determination and initial appeal by the CRM delivery body with appeal to the relevant RA as a 'last resort'.

Supplier Arrangements

Demand used as basis for charging

The paper focuses heavily on criteria of efficiency and equity in its assessment of the supplier obligation, which are defined as:

*"**Equity:** the market design should allocate the costs and benefits associated with the production, transportation and consumption of electricity in a fair and reasonable manner."*

*"**Efficiency:** market design should, in so far as it is practical to do so, result in the most economic overall operation of the power system."*

Simplicity is important too – there are still a large number of NHH meters currently installed across Ireland. Until HH meters are installed across the market, applying anything other than the current SEM approach which profiles the costs of capacity across all hours would be needlessly complex and likely to result in inequitable treatment of suppliers that supply particular market segments.

Reconciling charging with payments

[13] The investment impacts of future de-rating can be incorporated into auction bids rather than a technical assessment of potential capacity contribution.

[14] Some system operators do not provide firm connection dates to new plant so a requirement to have expected connection in advance of the CRM delivery year might result in discrimination against participants in one I-SEM jurisdiction. This could be separately addressed by the relevant RA.

Matching payments to the trading periods in which the payments arise is preferable to the alternative, but this decision should be cognisant of the likely constraints on the operation of a state-owned imbalance settlement agent.

Credit Cover

Credit cover requirements should be netted for the market as a whole – energy and capacity payments (negative exposure for suppliers, positive for generators) mirror difference payments (positive exposure for suppliers, negative for generators). The consultation paper states that netting may take place between option fees and difference payments but energy market exposure should also be incorporated too.

Exchange Rate Risk

The expected decision in the ETA workstream is to socialise currency costs – given the dual currency nature of I-SEM it seems appropriate that exchange cost variations are recovered by market operators through a socialised charge.

Institutional Framework

Regulatory Structure

We agree with the proposed delivery body and settlement agent choices for the I-SEM CRM. Choosing any other agent (i.e. alternative DA auction platform) will mean the agent does not necessarily have actual settlement data on metered demand.

The choice of whether to adopt counterparty contracts or capacity agreements should be dictated first of all by accounting issues. Without a single counterparty body available to take on the liabilities created by allocated reliability options this could potentially have damaging impacts on the ability of licence holders to finance their activities. SSE has previously commissioned a report on these issues that we could share with the RAs if they would find it useful.

Synergies and conflicts

The TSO, EirGrid Group has some clear conflicts as the likely imbalance settlement agent, delivery body, interconnection asset owner and interconnection asset developer. These should be managed through the Roles and Responsibilities workstream.