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I-SEM Energy Trading Arrangements – Building Blocks

Dear Kenny and Kevin

Thank you for the opportunity to respond to the RAs consultation paper on Building Blocks – the opportunity to discuss these issues prior to a formal consultation at the Rules Liaison Groups was very much appreciated. These have facilitated better industry understanding of the design considerations facing the RAs.

In addition, the discussion at the Rules Liaison Groups on implementing existing policies *generally* moved toward 'agreed' or 'common sense' positions that represented as-is implementation of policy or incremental improvements on existing implementation. We hope the value of information sharing and consensus building revealed by the RLG sessions is recognised in other I-SEM workstreams.

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. We have tried to reflect this experience in our response, which covers each of the different SEM policy areas that require translation into I-SEM.

The minded-to options for most building block topics appear sensible and reflect the discussion at the Rules Liaison Groups. However for two of the topics, **treatment of firm access** and **treatment of curtailment** SSE has concerns that the minded-to position in the consultation paper reflects ease of implementation rather than sensible and considered design.

In summary, SSE favours:

- Accounting for **generator transmission losses** at the participant side;
- **Dual interconnector loss factors**
- The definition proposed for **treatment of constraints**.
- No additional price risk or system operation costs allocated to **non-firm access.**
- A **modification to the priority dispatch definition**.
- A distinction between ex-ante trades by price making generation and 'deemed' trades by price taking generation in the **allocation of curtailment**.

- Retention of the existing **de-minimis level** or a move to 5MW.
- A **tariffing approach to currency costs.**
- Additional central forecasts published for **market information.**

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

Treatment of Transmission Losses

Generation Losses

Existing policy

The SEM Committee had originally decided to move away from Uniform TLAFs in a two step process, first implementing *compression* and then moving to *splitting*. They then decided to make the interim measure, compression, enduring. SSE still believes that the existing compressed TLAFs are:

- Imprecise: the RAs acknowledge that the loss factors used without compression *"are not much more representative of real time losses than a uniform loss factor"*
- Distortive: the impact analysis carried out by the RAs leading up to the SEM-12-024 decision clearly demonstrates that (more) efficient dispatch cannot be achieved through an algorithmic TLAF methodology.

If the existing methodology produces no useful economic information that can be used by a trader seeking to commit plant, a system operator seeking to dispatch plant or a board seeking to take an investment decision, we struggle to see why it should be retained. However, we acknowledge that given that the existing methodology creates *winners* and *losers* by virtue of redistribution between generators, so there will be no consensus on replacing it.

I-SEM Implementation

The approach set out by the SEM Committee for the treatment of interconnector losses would work:

- Trade ex-ante volumes at the trading point, net of losses, with generators accounting for losses in their commercial offers.
- Physical notifications at the station gate, gross of losses.

This results in the participant being responsible for their losses in the ex-ante markets. However, there are two different solutions for pricing balancing actions set out in the paper:

- Balancing actions are priced at the trading boundary by generators:
- Balancing actions are priced at the station gate by generators (and adjusted in settlement)

Both result in the same algebraic outcome:

QEIij = QMij*TLAFij - QBOAij*TLAFij – QIDij – QDAij

The question is whether these should be integrated into participant systems, or central systems. **We would prefer that balancing actions are priced at the trading boundary, allowing generators to manage their own losses.** While a station gate approach might offer advantages from the perspective of a single-unit generator, it does not take into account portfolio participants (like wind aggregators), who will provide a relatively large portion of traded volumes in I-SEM.

This approach aligns with the first - a participant is also responsible for losses in the balancing market. The paper states that:

"While option (a) is more consistent with the existing SEM, in that it is specific to the particular treatment of losses currently employed in dispatch, option (b) would be amenable to many different treatments of losses in dispatch, and thus may be a more flexible approach."

We would expect that current policy for transmission losses will be reviewed at some point in I-SEM; however we cannot see any reason why aligning ex-ante and ex-post markets and managing losses exclusively at the participant side would impede this.

Interconnector Losses

At the Rules Liaison Groups, the two different options for representing DC loss factors within EUPHEMIA were presented to participants; single loss factor or dual loss factors. The paper notes that, in relation to a single loss factor:

"While this approach would appear to be straightforward to understand and implement, it is likely that it would not be optimal. […] However, in this case the dead band arrived at does not represent either line correctly. Where the price differential between I-SEM and GB is between 2% and 4.6% no flow will happen between the two markets even though the price differential suggests that flows should occur through the Moyle."

This is correct. We would also add that representing the two interconnectors with a single loss factor would also be more difficult to unwind in the event that market splitting is required in either Ireland or GB. **SSE would therefore agree with the proposed implementation: representing the two interconnectors in market systems with their own loss factors.**

Outturn Loss Factor Correction

Accounting for the differences between ex-ante and outturn losses doesn't need to be resolved within the Building Blocks consultation. A tariffing approach has been suggested in the ***Markets*** Rules Liaison Groups sessions as an alternative to existing global aggregation. We think that this should be considered as a potential solution that would cover outturn losses[1] in the ***Markets*** consultation paper.

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[1] In addition to the profile errors, meter errors, time-switch errors, theft and CT/VT errors noted within the consultation paper.

Treatment of Constraints

Existing SEM policy is that:

"[U]nits which are the most economic to meet demand should not be at a financial disadvantage due to any constraints."

Implementing this policy should be relatively straight-forward, despite the far-reaching changes that are taking place in the transition to I-SEM. SSE believes that approach proposed in the consultation paper is elegant and simple with one caveat that has been recognised in the paper.

Depending on the solutions proposed in the market power workstream, a BOA[2] at a unit that will be constrained up in I-SEM may not be subject to bidding rules[3]. Nevertheless, we think that the ***Building Blocks*** decision paper should provide a definition for other I-SEM workstreams to build upon.

Therefore, the definition taken forward should be that:

- A plant that is constrained down due to a dispatch instruction shall pay back the lowers of its decremental bid price or the system balancing price; and
- A plant that is constrained up due to a dispatch instruction shall receive the higher of its incremental offer price or the Balancing price.

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[2] Bid Offer Acceptance.

[3] In SEM, local market power is neatly resolved by SRMC bidding.

Treatment of Firm Access

Existing SEM policy is relatively unusual in terms of its application of operational costs to generators defined as 'non-firm' under a shallow charging regime. A couple of different European approaches are summarised in a 2011 CEPA report for Ofgem's Project TransmiT[4] - we have added Ireland into the comparison:

Market	Energy Market	System Operational Costs	Transmission Connection	Use of Network
UK	Bilateral trading with separate buyer and seller spot balancing prices (non-locational)	Cost of constraints and losses are socialised and recovered through a non-locational Balancing Services UoS charge.)	Shallow	Zonal differentiation 27% Generation 73% Load
Germany	Bilateral trading with single spot balancing price (non-locational)	Cost of constraints and losses incurred by TSO, recovered through socialised UoS charges levied within TSO region	Shallow (Generation) Deep (Load)	Postalised within each separate TSO region 100% Load
Netherlands	Bilateral trading with single spot balancing price (non-locational)	Cost of constraints and losses incurred by TSO, recovered through socialised UoS charges	Shallow	Uniform nationally 100% Load
Spain	Trading predominantly through day-ahead (non-locational) energy market	Cost of constraints and losses recovered through uplift on energy market prices	Shallow	Uniform nationally 100% load
Ireland	Gross mandatory pool with single spot balancing price (non-locational)	Cost of (some) constraints incurred by TSO, recovered through non-locational imperfections charge.	Shallow	Locational differentiation 25% Generation 75% Load

[4] Review of International Models of Transmission Charging Arrangements – A report for Ofgem (2011), CEPA

The SEM concept of defining a difference between firm and non-firm access arises in both the allocation of system operational costs and transmission connection policy. The paper notes that the current application of this policy is that:

"Generators with non-firm access in the current SEM which are dispatched by the TSO are then assigned availability in the ex-post pool equal to their actual dispatch level, allowing them to be scheduled up to this level in the ex-post market if they are in merit. ***However, this current treatment works only in the context of an ex-post unconstrained pool."***

We'd start by characterising what the existing SEM is doing to a non-firm generator's volumes. By assigning availability in the ex-post pool to actual dispatch level, the SEM is:

- Setting a priority order to be used between generators with and without deep reinforcements in place.
- Reallocating the system operation costs of some constraints to generators in the latter category, by;
- Exposing that category of generator to volume risk for the 'non-firm' portion of their volumes above their SSC.

Firstly, SSE would state that under existing SEM policy (and sensible economic market design); new generators cannot be forced into a priority order that denies them access to ex-ante markets. This would be a departure from standard European market design and would have a number of malign consequences in terms of incentives to participate and incentives to deliver transmission infrastructure. **We agree with the SEM Committee's view that generators with non-firm access must be permitted to participate in the ex-ante markets.**

If they are allowed to participate in ex-ante markets, the next question to answer is how the system operation costs of a real-time constraint are allocated to the non-firm generator. At present, we'd characterise this as a 'volume risk'. Two of the three options from the RLG paper remain in the consultation paper:

- *"The plant must buy back any non-firm volumes at the Imbalance price. In such a scenario, its own decremental bid price would be ignored in the setting of the Imbalance price."*

- *The plant must bid to buy back any non-firm volumes in the Balancing Market at the DA price, or some price related to its actual trades (including trades in the IDM).*

The first of these exposes the non-firm generator to 'price risk' rather than volume risk – it also exposes the generator to a particular type of price risk – the cost of marginal energy balancing for the trading periods in which the constraint binds. Even if you could characterise this as a reallocation of system operation costs to the non-firm generator, it is impossible that this would be a cost-reflective reallocation.

The paper states that:

"Arguably this may be regarded as an inevitable consequence, and reflecting the lower value, of non-firm access."

This is a change to the value of non-firm access in SEM, not an accurate reflection of the SEM policy in I-SEM. Non-firm generators would be exposed to a different risk to SEM, which could only be effectively managed by avoiding ex-ante trades in periods where it expects that constraints may bind.

For the typical generator (single unit or portfolio aggregator), it is difficult to imagine that they can manage this risk by forecasting constrained volumes and trading them in the Day Ahead Market. It is also questionable whether the economic value unlocked by managing the risk would be equal to the cost of implementing the complex processes required to forecast constraints with an acceptable degree of accuracy.

The second option reflects existing SEM policy:

- A priority order for transmission access is set;
- Generators in the second category are allocated costs through exposure to volume risk[5].

We understand that this would be more complex to implement because defining the price at which a generator can have expected to contracted non-firm volumes reflects trades conducted in two different markets. However, this is not an insurmountable issue. Three options are available:

- You cash out non-firm volumes at the ex-ante trade price centrally
- You cash out non-firm volumes through a mandated DEC.
- You cash out at an 'expected' ex-ante trade price – the day ahead price would be simple and would incentivise participation in that time period.

Each solution will require some work – the first will require quite a complex solution utilising central trade data for each participant, the second will require monitoring and enforcement and the third will impose some limited price risk on non-firm generators that may discourage trading at the intraday stage. **However every single one of these solutions would be preferable to the creep of existing firm access policy into further allocation of system operation costs to non-firm generators[6].**

The arguments against these options in the consultation paper are weak. The paper states that *"Option b) as currently envisaged would give the opportunity to the generator to trade any volumes above its FAQ in the ex-ante market while having no exposure to the BM"*. This is false – Option b gives equal opportunity to all firm generation volumes, who have *access to* rather than *exposure to* the BM for their firm volumes, and restricts access to the balancing market for non-firm generation volumes.

The idea that it would create an additional incentive for non-firm generation to take a position in the ex-ante markets is not credible: managing unconstrained imbalance risk would be the primary consideration of a trading desk.

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[5] They are forced to buy back non-firm volumes that cannot be realised in real time dispatch at the price at which they can be expected to have sold them.

[6] Given that some categories of generators have no enduring policy for connection access in place at present, further allocation of system operation costs from TSO to non-firm generators is particularly biased against new entry or plant refurbishment for DS3.

Treatment of Priority Dispatch

Priority dispatch has been defined by reference to TSO procedures, rather than by reference to the market in SEM. This fits with the definition in 2009/28/EC which states that the member state should ensure that TSOs give priority to certain generating installations. SEM policy is clarified within **SEM-11-062** which states that:

"[The TSO will] adhere to an 'absolute' interpretation of priority dispatch whereby economic factors are only taken account of in exceptional situations."

Given that priority dispatch is a definition that applies to the TSO rather than the MO, we would agree that it has no relevance to the firm ex-ante markets that take place in advance of gate closure. We would agree with the RAs that the options presented in the Rules Liaison Group each overcomplicated the issue[7]. We would add a couple of clarifications for the solution proposed for priority dispatch generation:

I. *on the basis of observing prices and possibly trading in the ex-ante markets, decide on the physical notification reflecting the price making output at which it wishes to run given prevailing market conditions;*

II. *submit any incs and decs reflecting the price at which it is willing to deviate from its physical notification for its price making output;*

III. *Be dispatched by the TSO up to its absolute real-time availability in dispatch;*

IV. *The difference between notified output and availability is considered price taking.*

While you could state that these generators could just spill, without the additional clarification there is no clear priority order for the TSO to work to. Defining this volume as price taking could also resolve some of the RAs concerns about curtailment and incentives to trade. Defining priority dispatch in this way is in keeping with the existing SEM policy[8] whereas defining the volume that must be accommodated by the TSO under priority dispatch as being subject to forecast error, operational error in addition to system security and safety makes priority dispatch effectively irrelevant in I-SEM. The TSO can easily overcome forecast and operational error through ex-post calculation based on information from real-time SCADA, and should do so under its obligation to give priority.

[7] And left potential gaps open in terms of application of the existing policy.

[8] We acknowledge the concerns raised in relation to demand BSPs but believe that this can be addressed in the market power workstream.

Treatment of Curtailment

We would reiterate our views on the SEM Committee decision to remove any compensation for curtailed wind volumes in SEM-13-010. Removing the metric used to define the economic cost of an electricity system that cannot use zero marginal cost energy does not remove the economic cost. The slippage of timelines on DS3 solutions that would partially resolve this issue is a direct result of the transfer of risk away from the parties that can manage it.

Again, this is not to suggest that SSE believes that compensation for curtailment should be unlimited, as we stated in our response to SEM-12-028:

"A decision on compensation should be about how to share value between consumers and generators in a way that maximises the overall economic value delivered by renewable investment. Compensation should certainly not be about placing an open-ended liability on consumers to pay for capacity they do not need."

Under a different market structure, the economic cost becomes apparent again albeit in a different way - we are pleased to see that this has been acknowledged in the consultation paper:

"[N]ot compensating for DAM and IDM trades could act as a disincentive for wind to partake in these markets. Were this to be significant, the resulting omission of zero marginal cost wind from the DAM could act to increase the DAM price [...] ***Creating disincentives to trade in the DAM could affect the liquidity of that market and could ultimately have detrimental effects on the integrity of price formation."***

As the Building Blocks consultation makes clear, implementing an artificial distinction between one set of system operational constraints and another set of system operational constraints is not easy – lots of work is required to find a solution that implements the SEM-13-010 decision.

SSE believes that a least-worst approach would be defined as follows:

- Firstly, price taking volumes that have not been fixed in the ex-ante markets should be turned down to resolve the curtailment and paid according to their metered generation output.
- Then, any other curtailment volumes required from price making generators should be cashed out during a curtailment event in the same way that other generation deviations are cashed out – a pro-rata buyback of volumes at an expected transaction price.
- This makes a distinction between ex-ante trades by price making generation and 'deemed' trades by price taking generation which would incentivise participation in ex-ante markets.

If you don't distinguish between price making and price taking volumes, you remove incentives for wind to trade forward during periods in which curtailment is expected. The solutions proposed could allocate an imbalance risk that can only be effectively managed by withholding volumes from ex-ante markets. This potentially exacerbates the curtailment problem, and certainly makes it more difficult for participants and the TSO to manage.

De-minimis level

SSE does not believe that the de-minimis threshold is not really a fundamental **building block** of I-SEM market design per-se. We recognise that smaller market participants may not *“have adequate resources for market participation given the financial and administrative burden involved”* and that *“electricity generation may not be a central business of many of these participants.”*

However, these should not necessarily be a consideration in setting a de-minimis level, given that smaller participants can contract (and will still be required to contract as de-minimis) with market participants that can manage their output. **All that the de-minimis distinction allows for is some participants to contractually designate their generation as netted demand.** As the consultation rightly notes, the proportion of generation that has been able to designate their generation as demand has increased since the development of SEM and is reaching a level where it may have a material effect on participation in the market.

SSE would suggest that a 5MW threshold would be more appropriate, but that a decision on de-minimis threshold doesn’t necessarily need to be taken as part of the building blocks of I-SEM. A decision to align the de-minimis level with the existing Grid Code threshold can be taken after further analysis on the part of the TSO and RAs.

Treatment of Currency

SEM is a dual currency market, facilitating participation in both euro and pound sterling, with currency costs/benefits being socialised across the market. The existing implementation uses settlement and resettlement processes to allocate these to participants.

SSE believes that this is unnecessarily complex and time consuming, and that a tariffing approach would far better facilitate the underlying policy objective: socialising the costs of operating a dual currency market.

We would therefore support the minded-to position:

“Currency costs should be projected ex-ante and charged to suppliers as a tariff. Any differences between the projected and actual should be treated as a correction factor.”

Market Information

SEM’s transparency is one of the characteristics of the SEM that has been welcomed by participants and RAs. This can be seen in the implementation of REMIT transaction reporting, where SEMO can fulfil the criteria using existing data publication within a new template, without a requirement for any complex changes. However, a move to balance responsibility means that a number of different information sources will become increasingly important for participants to effectively manage their risk:

- TSO wind forecasts on a more regular intraday basis;
- TSO demand forecasts on a more regular intraday basis;
- Aggregate and individual physical notifications for plant;

- A central notice board for unavailability notifications;
- Imbalance flagging and tagging.

The net of the first three effectively provides a central forecast of system length. This is particularly important in a market in which the Balancing Market and Intraday market are open simultaneously. These publications have been captured in the consultation paper, with the exception of imbalance flagging and tagging.