Irish Wind Energy Association

IWEA Response to SEM-15-011

Integrated Single Electricity Market (I-SEM)

Energy Trading Arrangements Detailed Design

Building Blocks Consultation Paper

24th March 2015

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1. Executive Summary

IWEA welcomes the opportunity to respond to the consultation on the I-SEM Building Blocks Consultation. The new market design brings a number of challenges to market participants, and in particular to renewable generators, given the increased focus on day ahead trading and balancing responsibility. IWEA has supported the variation of Option 3 in the High Level Design consultation as we believe, among other things, it represents the best opportunity for more effective operation of interconnection and therefore reduction of curtailment. A trade-off in the selection of Option 3 has been increased complexity of trading relative to the Single Electricity Market. It is essential that the detailed market design proceeds in a manner which accommodates wind participation in the different market timeframes, and that the implementation of current SEM policy is not done in such a way as to add extra risk to operators who make attempts to trade in a prudent manner in the ex-ante market timeframes.

IWEA has been deeply engaged in the process to date through participation in the Rules Liaison Group which has been a useful forum for discussion and sharing of ideas. We suggest that this forum continues for all aspects of the detailed design. One suggestion IWEA would make to further enhance the utility of these workshops would be to provide a clear framework, with reference to the I-SEM High Level Design and its philosophy, within which detailed design issues are explained and debated. We also call for increased wider stakeholder involvement through regular industry fora, with at least one forum taking place per consultation at which an overview of the entire process is also provided.

It should be noted that many aspects under consideration in this consultation paper will be impacted by some of the aspects to be covered under the markets consultation. There is a significant level of interaction between different areas, some of which are to be discussed in the future, and these need to be taken into consideration before arriving at a decision. We believe this to be an iterative process and therefore in the absence of complete information on the detail of areas not yet covered, there may be a need to revisit some of the areas addressed in this consultation as more detail becomes available. This submission should be read in this context.

IWEA urges that detailed regulatory impact assessments are carried out in order to assess the impact on market participants of any decisions made, particularly where those decisions will clearly have a material impact on the business case for any asset class. This should take the form of a detailed qualitative and quantitative assessment (where reasonable). It is essential that a holistic view of the decisions on all aspects of the market design is taken, and the impact on different types of market participants can be assessed. In particular, decisions in relation to the treatment of items such as non-firm access and priority dispatch should be made within the wider context of the Capacity Remuneration Mechanism and the DS3 Programme.

Summary of Key Points

There are three aspects of the consultation paper which IWEA wishes to focus on in this summary.

Treatment of Constraint

IWEA supports the pricing arrangements for constraints as proposed in the paper that energy and non-energy balancing actions which are below the Balancing Market (BM) clearing price should be priced at the BM clearing price, and any "out-of-merit" actions taken are priced at the unit's offer/bid price.

The current policy for priority dispatch generation in the SEM grants a wind generator:

1. Absolute right to physically deliver its power, subject to security of operation of the grid; and
2. Assuming the generator has firm access to the grid, a guaranteed trade in the balancing market (i.e. the ex post schedule Market Scheduled Quantity (MSQ)) set at what the generator was available to produce, in the event that the generator is constrained/curtailed[1].

It is important that both these aspects are maintained in the I-SEM.

We propose that any firm wind energy constrained or curtailed that does not have an ex-ante trade should be compensated for such constraint/curtailment at the imbalance price[2]. This curtailed/constrained energy should be calculated automatically, as the difference between the out-turn availability and the dispatch instruction. This is consistent with existing policy, provides for equitable value of firm access for all players, and provides for a long-term signal to improve constraint/curtailment levels for low marginal cost renewables, which in turn is good for the consumer.

Compensation for Curtailment

IWEA maintains its position that the existing policy in relation to non-compensation for curtailment for the class of wind generators is discriminatory. At the very least, the market systems and rules must be technically able to deal with compensation for constraint and curtailment on an equal footing, considering the SEM Committee's existing policy does not come into play until 2018 and the market is scheduled to go-live in 2017.

We urge the SEM Committee to review their decision to remove compensation for curtailment in light of the requirements of the Network Balancing Code, delays to the DS3 programme, which was linked to the rationale for the decision to be implemented in 2018, and reduced export capabilities of the interconnectors.

Should curtailment remain non-compensated, there should not be exposure to imbalance pricing relative to ex-ante trades. A centrally managed "cash-out with resettlement" process, identical to the one proposed by IWEA in this response for non-firm trades, can facilitate this. At a minimum, ex-ante trades which promote appropriate interconnector flows, and therefore reduce curtailment, should be fully compensated.

Exposure to Imbalance for Non-Firm Generators and for Curtailed Generators

Our discussion here is without prejudice to our comments that policy on compensation for curtailment does need to be fundamentally revisited.

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[1] We note the current SEM policy of no such compensation for curtailment from 2018 onwards.

[2] For the avoidance of doubt, this would only apply to generators with firm access, and therefore there would be no such compensation to generators with non-firm access.

We strongly support that non-firm generation not be restricted from ex-ante trading.

IWEA believes that exposing non-firm constrained or curtailed ex-ante trades to imbalance pricing creates unacceptable risks for market participants. It acts as a disincentive to ex-ante trading, and could further exacerbate the lost energy in curtailment.

Therefore, IWEA supports the alternative approach: if a non-firm generator with an ex-ante trade is turned down, it should buy back the constrained volume based on the value of its ex-ante trades. This should be managed centrally, with the Balancing Market (BM) having access to the unit-based trades of the Day Ahead Market (DAM) and Intra-Day Market (IDM).

Summary of all other consultation topics

In relation to the other matters consulted on in this paper:

Treatment of Losses

- IWEA believes that the management of losses for generators should be exclusively managed at the participant side when interfacing with all markets (forwards market, DAM, IDM, BM). While it is a change from the current practice, this prevents inconsistency of treatment of losses when managed by several parties, and provides for consistency of treatment with demand and aggregated generation. This more than offsets the potential system implications on future changes to losses policy.
- IWEA believes that, in principle, interconnector losses should be treated separately. With hopefully better price convergence between I-SEM and BETTA over time, this allows for greater export with the lower loss factor interconnector exporting earlier. We note, however, the potential of physical constraints in BETTA to greatly restrict interconnector physical flows, and we believe that an analysis should be undertaken to see the impact of the loss representations on both financial and physical trading. If this review cannot be made now, a commitment should be made to review the optimal loss modelling methodologies for I-SEM consumers after I-SEM go-live.

Treatment of Priority Dispatch

- We concur with the proposed treatment of priority dispatch, noting that currently priority dispatch offers guaranteed trades to firm generation in the face of constraint, and that the TSO should be responsible for the submission of the required physical information into the balancing market. Consideration needs to be given in the settlement algebra that windfarms are not exposed to negative prices in such instances of constraint.

De Minimis Level

- The De Minimis level should not be reduced below 10MW, and that level can be maintained if the wind portfolio concept is well developed for generators greater than 10MW. If portfolio aggregation is not allowed, serious consideration should be given to increasing the De Minimis level to reduce the burden on those market participants.

Treatment of Currency

- IWEA supports the currency proposals in the paper.

Market Information

- IWEA stresses the importance of timely publication of data from a central location, particularly within-day to support IDM activities, and is supportive of the greatest degree of prudent transparency subject to market power mitigation strategies that may arise. Further engagement is required in relation to the frequency and timing of the information requirements.

2. Introduction

The Irish Wind Energy Association ("IWEA") is Ireland's leading renewable energy representative body representing more than 200 members involved in wind energy development in Ireland and also in Northern Ireland, through NIRIG (Northern Ireland Renewables Industry Group), set up in collaboration with RenewableUK.

IWEA represents members across the island with projects across the spectrum, in operation, under construction and awaiting connection. In Ireland IWEA members are involved in the majority of pre Gate 3 connected projects but also involved in more than 85% of the MW of contracted projects in Gate 1, 2 and Gate 3.

Through NIRIG we represent more than 25 company members that have developed over 85% of renewable generation operational in Northern Ireland today and who will contribute a significant majority of renewable energy required to deliver the 2020 targets.

The IWEA membership base includes all large, medium and many small developers as well as financial, legal advisory, consultancy, contractors and other service providers involved in the renewables sector in Ireland and Northern Ireland.

Our membership covers the full range of wind energy projects which all need to be considered in the new market design, including:

- >10MW wind farms in the market & under ROC support
- >10MW wind farms in the market & under REFIT support
- >10MW wind farms in the market & out of support
- Out of market wind farms & under ROC support (optional <10MW)
- Out of market wind farms & under REFIT support (optional <10MW)
- Out of market wind farms & out of support (optional <10MW)
- Uncontrollable wind farms & under ROC support (either <5MW or with derogations)
- Uncontrollable wind farms & under REFIT support (either <5MW or with derogations)
- Uncontrollable wind farms & out of support (either <5MW or with derogations)
- Future connections under new CfD support in NI
- Future connections under new yet to be defined subsidy scheme in ROI

These energy projects are owned and operated by a range of parties from small independent generators, medium and large developers, independent portfolio players and utilities. The resources and capabilities of these parties vary significantly and this needs to be taken into consideration in the market design. **<u>The current SEM allows for this range of capability and company resource, and this is a feature that needs to be maintained in order to promote equity and fairness in the transition to a new market.</u>**

3. Treatment of Transmission Losses for Generators

IWEA maintains our previously stated position that TLAFs should be uniform. IWEA has argued to date that the cost of losses should be socialized for wind generators as the TLAF does not achieve its purpose as a locational signal and generator sites have already been decided through the Gate process in Ireland and significantly determined by the planning process in Northern Ireland. By the time a generator has completed these processes, the TLAF may have changed significantly. As such, the relevance of cost reflectiveness as a primary objective is diminished and should not be a deciding factor in terms of methodology selection as it would be unfair to discriminate between adjustment factors for generator losses when developers were unable to take this consideration into their investment decision.

IWEA questions whether the treatment of transmission losses is consistent with how GB and other markets account for losses. It is our understanding that losses are socialized in many markets. Further consideration needs to be given to this to ensure that generation in the I-SEM is not at any disadvantage relative to cross border trades. Clarification needs to be sought as to how the treatment of losses is to be addressed under the Network Codes and whether the policy is aligned with the objectives of the target model.

Notwithstanding the above, IWEA understands that the consultation paper sets out the following propositions:

- Trades submitted to the DAM and IDM will have both volume and energy adjusted for losses and at the trading boundary. There is no proposal to have the DAM and IDM (despite being Unit based) to apply losses on behalf of market participants.
- Information provided to the TSO will be at the station gate of the facility.
- Trades submitted to the BM may be either at the trading boundary or the station gate.
    - There is no commercial difference in having trades in the BM at either location
    - It is a procedural issue as to who applies the loss factors
    - There are consequences for the potential flexibility in the future treatment of losses

We note that the view on losses is taken from the perspective of a single-unit generator. Portfolio aggregation of windfarms and demand with below De Minimis generation, however, cannot have a simple loss factor applied to it. If submissions to the balancing market were at the station gate and this principle was applied to all market participants, it is difficult to see how this would operate for portfolio participants.

Consequentially, in terms of consistency of treatment across all participants, it makes sense that submissions to the balancing market will be at the trading boundary.

We note that there is no proposal to manage submission of trades into the DAM and the IDM at the station gate. This is understandable, given the commercial nature of these markets. If submissions to the BM were made at the station gate in contrast it would mean:

- Consideration of losses would be managed by the participant for the DAM and IDM
- Consideration of losses would be managed by the Nominated Electricity Market Operator (NEMO) for the BM

This seems to create more entities than necessary managing the commercial impact of losses, and increases the potential for error. From a pragmatic point of view, while it is more complex and a deviation from existing practice, it appears more sensible for a single entity to manage the application of losses in all markets, i.e. by the participant. This also reduces any inconsistency with the treatment of portfolio participants.

Finally, the paper discusses the potential restrictions that such an approach may have on the implementation of future changes in losses policy. Given that participant trading desks would always have to account for such changes within the unit-based trading platform for DAM and IDM, IWEA does not see this as a compelling factor that would outweigh the consistent treatment of losses across all timeframes.

Conclusion

IWEA believes that the management of losses should be exclusively managed at the participant side when interfacing with all markets (forwards market, DAM, IDM, BM). While it is a change from the current practice, this prevents inconsistency of treatment of losses when managed by several parties, and provides for consistency of treatment with demand and aggregated generation. This more than offsets the potential system implications on future changes to losses policy.

Note that this response is without prejudice to IWEA's standing position that the existing losses policy does not deliver on its objectives (a signal for locating generators and an accurate recovery mechanism) and it should be replaced with something simpler in due course.

4. Treatment of Interconnector Losses

IWEA understands the consultation paper puts forward two options for the treatment of interconnection losses:

- Both Moyle and EWIC are treated as a single interconnector, and have a blended loss factor; or
- Moyle and EWIC are treated as separate interconnectors, with individual loss factors higher and lower than the blended loss factor respectively.

IWEA supports the treatment of separate loss factors, as it accurately represents the capabilities of both interconnectors. This approach also appears to deliver more export of power when prices start to converge between I-SEM and BETTA based on some basic analysis performed by IWEA. More export of power aids in the reduction of curtailment.

We strongly urge that the SEM Committee makes this decision in light of a full cost-benefit analysis at this time. Such analysis should take into account the differences between the commercially tradable nominal capacity of the interconnectors, and the interconnectors' physical capabilities which ultimately impacts the level of export and interconnector flows.

We therefore caveat this support for separate treatment of interconnectors, noting the potential for long-term export issues on interconnectors which are driven by BETTA transmission constraint issues, e.g. export into Scotland may be limited, as predicted under EirGrid's PGOR reports. In that context, as a point of I-SEM policy, the question should be asked whether Northern Ireland and Ireland renewable generation – and ultimately I-SEM consumers – must bear the cost of that inefficient barrier to trade. It may be appropriate to re-evaluate the treatment of losses on the two interconnectors so that they are "unconstrained" in aggregate. For example, irrespective of limitations caused to export by BETTA transmission, the first 250MW of export flow should occur from I-SEM when there is a 2% or greater differential between I-SEM and BETTA pricing, with that power carried on either available interconnector.

In general, we don't believe that the physical export capability of Moyle was fully factored into the analysis within the consultation paper. The tabular analysis sets out what presumably would be the *commercial* outcome of the treatment of loss factor. We believe that an understanding of what will happen with physical flows, and consequentially the impact on curtailment for renewables, should form part of the final analysis before any decision is made. For example, if Moyle is only physically capable of exporting 80MW but is capable of importing 250MW, is the blended loss factor different for import and export if the interconnectors are treated as a single interconnector[3]?

If decisions must be made now in order to progress I-SEM timelines without the benefit of such an analysis, a commitment to a review post I-SEM go-live to determine the optimal structure to the benefit of the consumer – both in terms of market trading to optimise prices and physical flows to optimise curtailment – should be carried out. The timing of such a review should be coordinated with the interconnector owners' sale of Financial Transmission Rights (FTRs).

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[3] For example, if Moyle is considered as a 80MW export-capable interconnector, a blended loss factor would be considered much closer to EWIC's loss factor (80 * .02 + 500 x .06) / 580 = 0.0544, than if was considered as a 250MW export interconnector (250 x .02 + 500 x .06) / 750 = 0.466. It is actually more beneficial for achieving physical export if the blended loss factor of 0.466 is utilised than having 80MW of achievable export at 0.02 loss factor and 500MW of achievable export at 0.06 loss factor.

Conclusion

IWEA believes that, in principle, interconnector losses should be treated separately. With hopefully better price convergence between I-SEM and BETTA over time, this allows for greater export with the lower loss factor interconnector exporting earlier. We note, however, the potential of physical constraints in BETTA to greatly restrict interconnector physical flows, and we believe that an analysis should be undertaken to see the impact of the loss representations on both financial and physical trading. If this review cannot be made now, a commitment should be made to review the optimal loss modelling methodologies for I-SEM consumers after I-SEM go-live.

5. Treatment of Constraints

IWEA supports the general principle being proposed in the consultation paper, i.e. that energy and non-energy balancing actions which are below the BM clearing price should be priced at the BM clearing price, and any "out-of-merit" actions taken are priced at the unit's offer/bid price[4].

IWEA would also like to discuss why existing constraint policy for priority dispatch renewable generation is not being considered as part of the I-SEM design. This along with the treatment of firm access and curtailment is one of the three major concerns with this paper.

Priority Dispatch and Constraints

The current policy for priority dispatch generation in the SEM grants a wind generator:

1. Absolute right to physically deliver its power, subject to security of operation of the grid; and
2. Assuming the generator has firm access to the grid, a guaranteed trade in the balancing market (i.e. the ex post schedule MSQ) set at what the generator could produce, in the event that the generator is constrained/curtailed[5].

It is important that both these aspects are maintained in the I-SEM. The second element of the above policy has not been included in the consultation paper, although the SEM Committee make some potential references to this possibility in the priority dispatch section of the paper.

For example, take a generator with no ex-ante trades that is capable of delivering its availability in power into the balancing market (e.g. 100MWh). It is, however, constrained to 40% of its potential output (i.e. 40MWh). Under such a scenario, the understood rules would simply treat this as 40MWh of sales at the BM price. The 60MWh which could have been produced has effectively disappeared. The loss of this low cost energy to the consumer is never recorded, and as such under a central dispatch market, there is no incentive for the TSO to correct the issue[6].

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[4] While it is not a matter for this consultation, IWEA believes that all "in merit" actions paid at the cleared BM price should contribute to the price formation of that cleared BM price. Not considering all "in merit" actions as contributors to the pricing stack would lead to unnecessary non-economic volatility in clearing prices.

[5] We note the current SEM policy of no such compensation for curtailment from 2018 onwards.

[6] Conversations in this area are complicated by the discussions in the industry around the de-linking of physical notifications and market positions. This note assumes that the TSO dispatch generation to particular levels against physical nominations using INCs and DECs, but participants only see costs relative to market trades, against which physical delivery and dispatch is measured for imbalances and balancing services respectively. For example, IWEA assumes that a generator with DAM and IDM trades of 50MWh, with a physical nomination (PN) of 60MWh and a dispatch of 50MWh, would simply receive its DAM/IDM pricing for its 50MWh trades.

There is another interpretation whereby the generator would receive DAM/IDM pricing for its 50MWh trades, but also sell a further 10MWh at the imbalance price, but pay back 10MWh at its DEC price. Under this circumstance PNs therefore have commercial meaning for the participant.

Finally, there is further complication around the IDM and BM being open simultaneously.

IWEA has not formed an opinion yet on linked or delinked PNs (noting the discussion on Priority Dispatch to follow), or indeed in the case of delinked PNs, the appropriate commercial impact for a participant of those PNs, i.e. no commercial significance, or a method of arbitraging INC/DEC offers with the BM clearing price.

It is of course correct to state that the windfarm owner could have traded the windfarm ex-ante, and therefore would have been entitled to constraint payments (subject to firm access). This would provide a signal to the TSO in terms of constraint costs. What this means, however, is that the TSOs' incentives to manage constraints are directly dependent on the financial trading patterns of participants, which seems an unnecessary and incorrect complication.

Moreover, the example given above is an extreme one with the generator producing 100MWh but the participant achieving no successful ex-ante trade. What is much more likely is that a reasonable and prudent operator of a windfarm will make all reasonable attempts to trade the windfarm's power in ex-ante timeframes. There will, nevertheless, be forecast inefficiencies in such trading. There may be also liquidity issues in the IDM to correct such trades. Such inaccuracies will result in inaccuracies in the windfarm's traded position, which in turn will impact the windfarm's ability to earn constraint payments. This undermines the concept of firm access more generally. It no longer grants commercial rights to sell the power you produce – it only grants commercial rights to sell the power that one can both accurately predict and for which there is sufficient liquidity in the timescales when the trade can be accurately predicted. This appears to be a diminution of firm access rights for variable generation that is happening without due consideration or impact assessment.

To ensure firm access retains its current value for variable generation, IWEA proposes that under the above scenario the full 100MWh of potential electricity is sold unconstrained in the BM market at the BM clearing price. Generators would be obliged to pay back their DEC, which assuming competitive bidding driving DECs towards SRMC, would be zero for a windfarm. This can be carried out through similar settlement rules in play for today's market, i.e. an "availability" signal should be automatically profiled by the TSO and submitted to the NEMO for appropriate settlement[7].

A possible concern with this scenario is that the incentive to enter into ex-ante trades in order to receive a constraint payment would be lost. IWEA is of the view, however, that the DAM will represent a stable and liquid market and therefore receiving the DAM price remains a sufficient incentive by itself for any reasonable and prudent operator with basic trading functionality. Similarly, if a participant is neither equipped for nor can afford DAM trading, receiving DAM-priced constraint payments will not represent sufficient revenue to suddenly make DAM trading worthwhile.

Finally, the current BM proposals (an ex-ante trade is required for a constraint payment) are primarily based on BETTA arrangements. Underlying the BETTA arrangements, however, is a fully self-dispatch market that allows trades to be secured outside of common platforms. In BETTA, Physical Notifications (PNs) made one hour out have definite commercial meaning. That has not yet been established within this market design (see Footnote 6).

Therefore the proposed BM constraint in this paper deserves careful consideration on its own I-SEM merits, given the key differences of a centrally dispatched market with priority dispatch from that in BETTA. We note the importance of the interaction of this position with the appropriately allowable DECs for windfarms, the treatment of that DEC relative to the "firm" position in the BM market, and

[7] This is somewhat similar to the alternative view in footnote 6, replacing PNs with TSO managed availability signals based on windfarm SCADA. This is somewhat aligned with the SEMC thinking on Priority Dispatch within the consultation paper as well. See section on Priority Dispatch for some further discussion.

scenarios of negative BM pricing. IWEA wishes to avoid the scenario where a windfarm that has been curtailed with no ex-ante trade is exposed to negative pricing.

Conclusion

IWEA supports the pricing arrangements for constraints as proposed in the paper that energy and non-energy balancing actions which are below the BM clearing price should be priced at the BM clearing price, and any “out-of-merit” actions taken are priced at the unit’s offer/bid price.

However we put forward that constraint payments should be made to firm generation with no ex-ante trades at the imbalance market price for constrained energy, as this implements existing SEM policy while at the same time providing a signal to the TSO to manage the constraints arising.

6. Treatment of Priority Dispatch

The SEM Committee have proposed that Priority Dispatch generation may choose its level of commercial risk in securing a trade in ex-ante markets. Having Priority Dispatch, the TSO would take a generator's Physical Nomination which should represent its full potential output. Those elements of the Physical Nomination that were not covered by an ex-ante trade would effectively be Price Taking in the BM.

IWEA supports this concept, with three qualifications.

1. We believe there should not be a submitted Physical Nomination for windfarms based on its expected output. Instead, the "price-taking" energy in the BM should be based on what the windfarm could generate, based on its availability to generate. This covers off the concept of constraints for priority dispatch generation covered earlier.
2. The windfarm itself should not be required to submit its expected output an hour before real-time. Priority dispatch does not limit the rights of wind generation to deliver power based on what windfarm owners expect to produce within the next hour. Priority dispatch requires the TSO under the Renewables Directive to accept all power capable of delivery from the windfarm in real time, subject to safe, secure operation of the system. Therefore, the "Physical Nomination" referred to within the SEM Committee proposal should be replaced with:
    i. An availability signal calculated from real-time SCADA, limited only by firm access quantity if the plant has been constrained, and this should be
    ii. Created ex post by the TSO on behalf of the windfarms and windfarm portfolios for utilisation by the NEMO for imbalance settlement
3. Consideration needs to be given in the settlement algebra that windfarms are not exposed to negative prices in such instances of constraint.

IWEA believes that absolute priority dispatch remains the gold standard principle that should be adhered to, while recognising the practical and economic difficulties that this incurs. IWEA believes that there are several projects and activities now, for example the delayed DS3, which fall well short of the "at any cost" paradigm explicit in absolute priority dispatch. We believe that the example given in the paper of the exceptionally expensive Balancing Service Provider is a matter more suited to market power concerns.

Conclusion

We concur with the proposed treatment of priority dispatch, again noting the qualifications above that currently priority dispatch offers guaranteed trades to firm generation in the face of constraint, and that the TSO should be responsible for the submission of the required physical information into the balancing market. Consideration needs to be given in the settlement algebra that windfarms are not exposed to negative prices in such instances of constraint.

7. Treatment of Non-Firm Access

Many of the comments regarding non-firm access in this section also relate to non-compensation to curtailment (without prejudice to IWEA's position that the curtailment policy is incorrect and should be revisited).

IWEA understands that the paper puts forward two proposals:

- Ex-ante trades made by non-firm generators, should that generator be constrained, be cashed out at the imbalance price; or
- Ex-ante trades made by non-firm generators, should that generator be constrained, be settled at a DEC at a price calculated from the value of those ex-ante trades.

The consultation paper makes these proposals within the context that non-firm generators should not in effect be restricted from making ex-ante trades by virtue of the commercial arrangements in place. IWEA strongly supports that concept: non-firm generation not be restricted from ex-ante trading. There is over 3,000MW of firm grid capacity to come online between now and 2020 in Ireland alone[8]. To restrict such potential levels of generation from ex-ante trading in the interim would create an inconsistency between the overall market design with its emphasis on the DAM and IDM and potentially increase costs to the consumer as a result. Furthermore, interaction with the Northern Ireland Renewable Contracts for Difference, and non-firm generation in Northern Ireland would be undermined[9].

Appendix 1 to the response examines the two options in turn. The first option requires the paying back of ex-ante trades, plus a new imbalance risk when non-firm ex-ante trades are physically constrained. The second option, while more complicated to implement, just requires the paying back of ex-ante non-firm trades. The second option is more aligned with the current policy in the SEM.

IWEA is uncertain from a policy perspective what has justified the proposed change in treatment that non-firm generation should be exposed to imbalance pricing, particularly where the price risk is as a result of attempts to trade prudently in the DAM and, in so doing, improving liquidity. While the new market by itself is an imbalance market, that does not mean that price can be arbitrarily applied to generators' positions without a coherent rationale. This rationale has not been presented in the paper.

The size of the imbalance risk faced by a prudently traded windfarm under the first option is not evaluated within the consultation paper. In the absence of quantification of that risk, the correct strategy is to attempt to predict constraint and not trade it in the DAM. This acts as a disincentive to trade in ex-ante markets for predicted constrained volumes.

[8] http://www.eirgrid.com/media/ResultsfromEirGridFAQAnalysisforGate3publishedOctober2013.pdf

[9] While not a topic under consultation here, we also note that non-firm wind generators, constrained or curtailed pre 2018 or post 2018, and indeed non-firm generators in general receive capacity payments under current policy. As we understand the new Capacity Remuneration Mechanism (CRM) design, it is important for a generator with a Reliability Option to be traded and earning money in the CRM reference market from a risk perspective. If non-firm access presents a barrier to earning money in the CRM reference market, then non-firm generators face a basis risk (i.e. they will be earning revenues from a different market than in which the Reliability Option is struck, or it may be exposed to imbalance costs). Firm generators will not experience this. As new entrant generators tend to be non-firm, this could create a bias against new entrants in the CRM auction.

In the light of no discussion why non-firm generation should face imbalance risk from a policy perspective, and the lack of quantification of the commercial incentives that arise, it is IWEAs opinion that anything that creates risk in taking a DAM position is unacceptable, and therefore IWEA supports the second option: cash-out at ex-ante trade price. We suggest that the only workable "Ex-ante Trade" price should be **managed centrally**, calculated from ex-ante trades. This requires the balancing market (BM) to have access to the unit-based trades of the DAM and IDM. Pushing this requirement back out to market participants to calculate an appropriate DEC price would result in a multiplication of different processes managing the same calculation, making changes in policy difficult to coordinate. Furthermore, the perceived reduced complexity in the central systems would be offset by the inevitable monitoring and governance regime that would be necessary to ensure market participants were behaving appropriately.

There is one argument presented in the consultation paper (apart from the technical complications) presented against the "Cash-Out at Ex-ante Trade" proposal. The SEM Committee have invited opinion on the view that this approach would lend itself to inappropriate and/or exaggerated non-firm trading positions in the day-ahead market, under the assumption that the participant would not be exposed to any risk in doing so.

We believe this argument misrepresents the reality of most non-firm generators in Ireland and Northern Ireland. For the most part, non-firm generators can frequently run with limited risk of constraints. Therefore, exaggerated DAM trading would be typically caught by imbalance risk <u>when not constrained</u>, which would be the majority of the time. Situations where non-firm generators have predictable long-term constraints that would allow dubious trading strategies are rare, and in any event are best captured through direct TSO contracting as done in BETTA, or through local market power mitigation measures.

Conclusion

For non-firm generation, there should not be exposure to imbalance pricing relative to ex-ante trades. A centrally managed "cash-out with resettlement" process can facilitate this.

8. Treatment of Curtailment

The market systems must be able to deal with compensation for constraint and curtailment on an equal footing, considering the SEM Committee's existing policy does not come into play until 2018 and the market is scheduled to go-live in 2017.

In that context, the same functionality should be applied for curtailment that is proposed for cash out of non-firm traded positions in the event of constraint. This is consistent with one of the presented SEM Committee's option for the treatment of curtailment, i.e. Cash Out and Post Processing.

The arguments that applied to non-firm generators facing imbalance risk apply equally to curtailed generators facing imbalance risk, and they will not be restated here. There is, however, a further sting in the tail when it comes to curtailment. Should generators choose to try to predict curtailment and avoid this risk by not trading ex-ante, it has the highly perverse outcome of potentially raising DAM prices, reducing interconnector export, and potentially making curtailment worse. The SEM Committee have acknowledged the likelihood of increasing the DAM price in the consultation paper:

"However, not 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."

Should the Policy Still Hold?

IWEA maintains its position that the existing policy in relation to non-compensation for curtailment for the class of wind generators is discriminatory. The definition of curtailment, i.e. that any generator out of a class of generation may be turned down to resolve a system-wide issue, applies equally to conventional generation providing for operational reserves in the event of conventional generator trip. Yet, the conventional generation fleet are compensated for such re-dispatch. Similarly, interconnectors which contribute to a SNSP limit (Moyle and EWIC do not provide inertia) have been given priority for a system security issue, going beyond the commercial priority afforded to them under the dispatch hierarchy. Therefore the SEM Committee has taken a clearly discriminatory view between renewables and conventional generation and interconnection, with no justification as to why.

It is also obvious that the process to reach the curtailment decision took place in the entirely different context of the centrally dispatched gross mandatory pool SEM at a point where non-compensation would not impact market efficiency, however we have significant concerns that this decision may impact market efficiency for I-SEM. <u>The manner in which that decision has been transposed into an entirely new legal framework and market design without any re-evaluation or review is fundamentally flawed in terms of due process. It is flawed because the decision was made both in advance of the SEM Committee's own decision on the High Level Design, and also in advance of the overarching regulations for the Electricity Balancing market being agreed in the comitology process.</u>

<u>**IWEA is therefore stating that the issue of non-compensation for curtailment does need to be reopened and re-examined in light of all new relevant facts.**</u>

Outside of the long-standing and seemingly ignored arguments regarding discrimination, and indeed that unmonitored and uncontrolled curtailment is a long-term loss to the consumer which should be recognised in a market signal, there are new facts at play which have not been evaluated by the SEM Committee within their Building Blocks consultation.

These facts include the new network balancing code, which has as principles:

- the creation of economic signals to promote suitable investments;
    - With non-compensation for curtailment, the actors that can manage said costs (TSO and SEM Committee) have no mechanism to objectively judge the success of their actions in doing so;
- the facilitation of harmonisation of Imbalance Settlement mechanisms;
    - IWEA is not aware of any other market design in Europe that actively promotes such different treatment of a class of generators. At the very least, it raises the potential scenario where windfarms in Great Britain could be paid as Balancing Service Providers within a Coordinated Balancing Area (CoBA), reducing their output at a low or negative DEC price, while I-SEM windfarms are being contemporaneously curtailed with no compensation as part of the same CoBA.
- provision of a fair distribution of the benefits and costs associated to the Balancing Markets;
    - Windfarms will be positively discriminated against offering a price for downward balancing capability under certain circumstances.

Further considerations also include the re-evaluation of the concept of tie-break's interaction with the commercial treatment proposed for priority dispatch generation in the market in the consultation paper. A generator that has achieved a net price of €100/MWh in DAM and IDM trading but is curtailed has to hand-back more money than a generator which has earned €50/MWh in ex-ante trading that is also curtailed[10].

The non-payment for curtailment also needs to be considered within the wider incentives within the new market. At a minimum, ex ante trades which promote appropriate interconnector flows, and therefore reduce curtailment, should be considered as the trigger for curtailment compensation. Curtailment is likely to be systemic and material for wind generators. Unlike compensation for constraint compensation for curtailment could be sufficiently material and of predictable value to incentivise wind generators to trade day-ahead.

Finally, outside of the I-SEM scope is the changing physical environment, with a continually delayed DS3 programme, with a delayed RoCoF standard and system services, and interconnection with physical restrictions on the delivery of exported power both North and South with no sign of rectification.

Conclusions

Compensation for curtailment should be revisited in light of the legal requirements of the Electricity Balancing Network Code, and wider issues around the delay in timelines for DS3 delivery and issues relation to interconnector operation. Should curtailment remain non-compensated, there should not be exposure to imbalance pricing relative to ex-ante trades. A centrally managed "cash-out with

[10] It could be argued that simply exposing generators to imbalance risk (rather than Cash-Out and Post Processing) would allow generators to see the value of their superior trading skill. IWEA argues that the imbalance risk acts as a disincentive for those ex ante trades to occur in the first place.

resettlement” process, identical to the one proposed by IWEA in this response for non-firm trades, can facilitate this. At a minimum, ex-ante trades which promote appropriate interconnector flows, and therefore reduce curtailment, should be **fully** compensated.

9. De Minimis Level

IWEA welcomes the consultation on the De Minimis level within the I-SEM. De Minimis trading is associated with simpler trading (the generators can be aggregated into a demand portfolio which is given a deemed trade), and easier registration (the generators can be assigned to a supplier in the retail market with much shorter timeframes, lower administration, and lower costs[11]).

As long as the wind portfolio aggregation design, including the operation of the Aggregator of Last Resort, for generators greater than 10MW is properly developed, and offers broadly equivalent economies of scale for registration and trading that below De Minimis generation will enjoy, IWEA believes that the below De Minimis generation limit can remain at 10MW. Below De Minimis generation will be afforded the choice of joining an aggregated portfolio, or remain netted off demand. If, however, the economies of scale are not forthcoming from the wind portfolio aggregation design, the SEM Committee should seriously consider increasing the De Minimis level. It is simply inappropriate to require small generators under than 10MW to face the full complexity of I-SEM and all that it entails as a single unit.

The consultation paper also refers to the possibility of reducing the De Minimis level to 5MW to align with the Grid Code. IWEA does not believe that this is appropriate as the Grid Code refers to the technical capability of the plant and is not based on market participation. The forthcoming Network Code on Requirements for Generators (RfG) will also be changing the level at which the Grid Code applies, and this should not have implications for market participation. The specification in the RfG, for smaller generators connected on the Island of Ireland, relative to the specification in the RfG for small generators connected in other European synchronous areas, is more stringent and therefore investors and operators have higher Grid Code compliance costs. There is no justification, with the introduction of I-SEM, to change the existing De Minimis policy to reflect the threshold set out in the Grid Code, which has been justified on the basis of technical system operation requirements.

Conclusion

The De Minimis level should not be reduced below 10MW, and can be maintained at that level if the wind portfolio concept is well developed for generators greater than 10MW. If portfolio aggregation is not allowed, serious consideration should be given to increasing the De Minimis level to reduce the burden on those market participants.

[11] The SEM Committee consultation incorrectly states that UoS charges can be avoided by below de minimis trading. All DUoS and TUoS for QH and HH metered customers (such meters are necessary to be considered as a below de minimis generator) are levied on the individual site meter readings without netting of export. Therefore full TUoS and DUoS apply. Only SEM wholesale market charges are reduced, as SEM charges are billed on fully aggregated and netted demand.

10. Treatment of Currency

IWEA supports the consultation paper's position on creating an annual charge for currency in the I-SEM. The current currency charges levied on generation and demand are current highly opaque in the SEM. While these charges are quite immaterial, it would be good to understand the net cost of managing currency in the market, and potentially incentivise its management in the future if needs be. This is best done through an annual tariff review.

There is a risk that if there is a significant exchange rate change in one day that a Northern Irish generator would have to carry this risk. Although, the fact that this risk exists, for even if only for a small timeframe, generators in Northern Ireland will have to provide credit cover to cover this. Northern Irish generators should not be exposed to this risk when Republic of Ireland generators are not, this risk should be socialised across all generators.

Conclusion

IWEA supports the currency proposals in the paper.

11. Market Information

IWEA welcomes the transparency in the proposed market design, on similar levels to the SEM design. We believe, along with the existing levels of published data being maintained, that the following data should be included and published centrally:

- Regional wind forecasts from the TSO, updated regularly intraday
- Load forecasts from the TSO, updated regularly intraday
- Regular updates on interconnector current position and schedules as IDM markets clear
- Updates on what proportion of wind trades are exported to BETTA or serve domestic I-SEM demand
- Views on whether the market is "long" or "short", updated regularly intraday

Further engagement is required in relation to the frequency and timing of the above information requirements.

The SEM Committee should push – where possible – to achieving equivalent levels of transparency with our trading partners in BETTA.

With all publication of data, care must be taken regarding intra-and-extra-bidding zone market power, and this will need to be a consideration for all parties.

Finally, publication of data to the public and not just market participants should be considered within the overall IT system specifications from an early stage. While the level of access to data from SEM-O is commendable, its public-facing implementation relies unnecessarily on SEM-O resources to deliver and maintain a bespoke data retrieval service where the interface or quality of data publication falls short of user expectation.

Conclusion

IWEA stresses the importance of timely publication of data, particularly within-day to support IDM activities, and is supportive of the greatest degree of prudent transparency subject to market power mitigation strategies that may arise. Further engagement is required in relation to the frequency and timing of the information requirements.

12. Conclusions and Next Steps

IWEA looks forward to continued engagement on the I-SEM detailed design. We note that the upcoming Markets Consultation is likely to have a significant bearing on some of the aspects discussed under this consultation and note that this response should be read in that context. We welcome the approach to have an overall decision on the detailed design of the energy trading arrangement ensuring that the overall design is fit for purpose.

IWEA urges that detailed regulatory impact assessments are carried out in order to assess the impact on market participants of any decisions made. It is essential that a holistic view of the decisions on all aspects of the market design is taken, and the impact on different types of market participants can be assessed. In particular, decisions in relation to the treatment of items such as non-firm access and priority dispatch should be made within the wider context of the Capacity Remuneration Mechanism and the DS3 Programme.

IWEA would welcome the opportunity to meet with the SEM Committee or the Project Team to discuss our comments further.

Summary of Key Points

Treatment of Constraint

IWEA supports the pricing arrangements for constraints as proposed in the paper that energy and non-energy balancing actions which are below the Balancing Market (BM) clearing price should be priced at the BM clearing price, and any “out-of-merit” actions taken are priced at the unit’s offer/bid price.

The current policy for priority dispatch generation in the SEM grants a wind generator:

1. Absolute right to physically deliver its power, subject to security of operation of the grid; and
2. Assuming the generator has firm access to the grid, a guaranteed trade in the balancing market (i.e. the ex post schedule Market Scheduled Quantity (MSQ)) set at what the generator was available to produce, in the event that the generator is constrained/curtailed[12].

It is important that both these aspects are maintained in the I-SEM.

We propose that any firm wind energy constrained or curtailed that does not have an ex-ante trade should be compensated for such constraint/curtailment at the imbalance price[13]. This curtailed/constrained energy should be calculated automatically, as the difference between the out-turn availability and the dispatch instruction. This is consistent with existing policy, provides for equitable value of firm access for all players, and provides for a long-term signal to improve constraint/curtailment levels for low marginal cost renewables, which in turn is good for the consumer.

[12] We note the current SEM policy of no such compensation for curtailment from 2018 onwards.

[13] For the avoidance of doubt, this would only apply to generators with firm access, and therefore there would be no such compensation to generators with non-firm access.

Compensation for Curtailment

IWEA maintains its position that the existing policy in relation to non-compensation for curtailment for the class of wind generators is discriminatory. At the very least, the market systems and rules must be technically able to deal with compensation for constraint and curtailment on an equal footing, considering the SEM Committee's existing policy does not come into play until 2018 and the market is scheduled to go-live in 2017.

We urge the SEM Committee to review their decision to remove compensation for curtailment in light of the requirements of the Network Balancing Code, delays to the DS3 programme, which was linked to the rationale for the decision to be implemented in 2018, and reduced export capabilities of the interconnectors.

Should curtailment remain non-compensated, there should not be exposure to imbalance pricing relative to ex-ante trades. A centrally managed "cash-out with resettlement" process, identical to the one proposed by IWEA in this response for non-firm trades, can facilitate this. At a minimum, ex-ante trades which promote appropriate interconnector flows, and therefore reduce curtailment, should be fully compensated.

Exposure to Imbalance for Non-Firm Generators and for Curtailed Generators

Our discussion here is without prejudice to our comments that policy on compensation for curtailment does need to be fundamentally revisited.

We strongly support that non-firm generation not be restricted from ex-ante trading.

IWEA believes that exposing firm or non-firm constrained or curtailed ex-ante trades to imbalance pricing creates unacceptable risks for market participants. It acts as a disincentive to ex-ante trading, and could further exacerbate the lost energy in curtailment.

Therefore, IWEA supports the alternative approach: if a non-firm generator with an ex-ante trade is turned down, it should buy back the constrained volume based on the value of its ex-ante trades. This should be managed centrally, with the Balancing Market (BM) having access to the unit-based trades of the Day Ahead Market (DAM) and Intra-Day Market (IDM).

Summary of all other consultation topics

In relation to the other matters consulted on in this paper:

Treatment of Losses

- IWEA believes that the management of losses for generators should be exclusively managed at the participant side when interfacing with all markets (forwards market, DAM, IDM, BM). While it is a change from the current practice, this prevents inconsistency of treatment of losses when managed by several parties, and provides for consistency of treatment with demand and aggregated generation. This more than offsets the potential system implications on future changes to losses policy.
- IWEA believes that, in principle, interconnector losses should be treated separately. With hopefully better price convergence between I-SEM and BETTA over time, this allows for greater export with the lower loss factor interconnector exporting earlier. We note, however, the potential of physical constraints in BETTA to greatly restrict interconnector physical flows, and we believe that an analysis should be undertaken to see the impact of

the loss representations on both financial and physical trading. If this review cannot be made now, a commitment should be made to review the optimal loss modelling methodologies for I-SEM consumers after I-SEM go-live.

Treatment of Priority Dispatch

- We concur with the proposed treatment of priority dispatch, noting that currently priority dispatch offers guaranteed trades to firm generation in the face of constraint, and that the TSO should be responsible for the submission of the required physical information into the balancing market. Consideration needs to be given in the settlement algebra that windfarms are not exposed to negative prices in such instances of constraint.

De Minimis Level

- The De Minimis level should not be reduced below 10MW, and that level can be maintained if the wind portfolio concept is well developed for generators greater than 10MW. If portfolio aggregation is not allowed, serious consideration should be given to increasing the De Minimis level to reduce the burden on those market participants.

Treatment of Currency

- IWEA supports the currency proposals in the paper.

Market Information

- IWEA stresses the importance of timely publication of data from a central location, particularly within-day to support IDM activities, and is supportive of the greatest degree of prudent transparency subject to market power mitigation strategies that may arise. Further engagement is required in relation to the frequency and timing of the information requirements.

Appendix

Non-Firm Access Treatment Option 1: The first option creates an imbalance risk for non-firm trades. For example, a 20MW windfarm is partially firm for 15MW. It accurately trades 18MWh in the DAM what it could deliver in a given hour. It is turned down to 14MW by the TSO. Under this proposal the windfarm would:

- Receive a DAM trade for 18MWh
- Buy 3MWh energy from the imbalance market at the BM price
- Pay a DEC (probably €0/MWh) for the 1MWh
- This leaves the generator with net 15MWh at the DAM price and 3MWh priced at (DAM – BM) price.

This (DAM – BM) cash out price can clearly be positive or negative, and therefore it represents a risk to the firm revenues generated for 15MWh trade. The generator is left with two options. Either it:

- accepts this risk, assuming in the long-run that the (DAM – BM) price applied to the constraint volumes at those times trends to zero or comes in at an acceptable cost; or
- does not accept this risk, and therefore avoid ex-ante trades where it is confident there is a chance of constraint.

Non-Firm Access Treatment Option 2: The second option is to treat generation much as it is today, with firm trades not impacted by non-firm risk, and therefore no incentives placed on market participants to avoid ex-ante trades for non-firm capacity. Under this proposal (same trading and physical scenario, 20MW windfarm is partially firm for 15MW. It accurately trades 18MWh in the DAM what it could deliver in a given hour. It is turned down to 14MW by the TSO) the windfarm would:

- Receive a DAM trade for 18MWh
- Buy 3MWh energy from the imbalance market at the same price achieved for the ex-ante trades, in this case the DAM price
- Pay a DEC (probably €0/MWh) for the 1MWh
- This leaves the generator with net 15MWh at the DAM price in all cases, as the 3MWh is priced at (DAM – Ex-ante Trade) price.

This adds some complication into calculating the "Ex-ante Trade" price[14] when DAM trades are supplemented by several IDM trades at different prices. Irrespective, this is an algebraic problem that can be resolved. Technically, all trades related to the unit must be collated from the DAM and IDM and made available to the BM calculations. As all trading in I-SEM is proposed to be Unit-based, this is a complicated logistical challenge rather than an issue of unresolvable complexity.

The benefit of this complication, however, is that it allows existing SEM policy to remain untouched. Firm trades are firm trades, and non-firm positions if they are unwound in dispatch do not impact the achieved value of the firm trade.

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[14] If the DAM trade for 18MWh was instead made up of 15MWh at DAM @ €70/MWh and 3MWh in IDM @ €40/MWh in the IDM, a detailed design question emerges. Can a participant say that the later incremental trade was for the non-firm portion, and only pay back 3MWh x €40/MWh, or should the participant be required to pay back a blended weighted average of the two trades, i.e. (15 x 70 + 3 x 40) / 18 = €65/MWh?