Integrated Single Electricity Market (I-SEM)
Energy Trading Arrangements Detailed Design

Building Blocks Consultation Paper SEM-15-011

A Submission by EirGrid plc.

25 March 2015

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1 EXECUTIVE SUMMARY

EirGrid Group welcomes the publication of the I-SEM ETA Building Blocks Consultation Paper and the opportunity to respond to the consultation.

EirGrid is supportive of the process undertaken so far by the SEM Regulatory Authorities which has seen the development of thinking around individual building blocks of the market both through discussion papers and workshops held over the last six months.

The Building Blocks Consultation paper presents a number of detailed ideas aimed at implementing existing SEMC policies in the I-SEM. EirGrid is broadly supportive of the approaches put forward and has included in its response some additional thoughts in respect of these proposals.

We continue to be supportive of the proposals for maintaining payments for constraints in the I-SEM. However, we feel it is prudent to reiterate our previous comments with regard to potential increases in dispatch balancing costs with the move to the I-SEM. We consider these may arise due to the nature of the day-ahead and intraday markets where contract positions will likely be less reflective of actual generators' physical capabilities than the current Market Scheduling and Pricing software. Moving from a perfect hindsight market to an ex-ante market based on forecasts will also be a contributory factor. It is important that consideration is given to ways in which to manage these costs through the development and implementation of the I-SEM and via the associated regulatory arrangements. In this context it is also important that the TSO is sufficiently financed to perform its functions including managing these and other costs.

EirGrid believes that approaches to the settlement of curtailment and non-firm constraints based on mandating generators to bid decremental prices reflective of their ex-ante revenues may prove onerous and cumbersome, especially for small players. We support options with cashing out at the imbalance price as they are less complex yet largely reinforce the correct incentives. EirGrid believes that the treatment of curtailment should not be applied differently to day-ahead and intraday market volumes than to balancing market volumes.

Careful consideration is required with respect to priority dispatch generation and its treatment in the I-SEM. It is important that these generators are facilitated and not subjected to an undue administrative burden that might create a barrier to trade. Within our response we have considered the proposals presented thus far and have put forward our own suggestion on how priority dispatch can be accommodated in the I-SEM, which we are open to discussing in more detail.

EirGrid reaffirms its commitment to working with both the industry and the Regulatory Authorities to assist in the development of effective and appropriate I-SEM arrangements and to support the delivery of the new market arrangements by Q4 2017.

2 INTRODUCTION

2.1 EIRGRID PLC

EirGrid holds licences as independent electricity Transmission System Operator (TSO) and Market Operator (MO) in the wholesale trading system in Ireland, and is the owner of the System Operator Northern Ireland (SONI Ltd), the licensed TSO and MO in Northern Ireland. The Single Electricity Market Operator (SEMO) is part of the EirGrid Group, and operates the Single Electricity Market on the island of Ireland.

Both EirGrid, and its subsidiary SONI, have been certified by the European Commission as independent TSOs, and are licenced as the transmission system and market operators, for Ireland and Northern Ireland respectively. EirGrid also owns and operates the East West Interconnector, while SONI acts as Interconnector Administrator for both of the interconnectors that connect the island of Ireland and GB.

EirGrid and SONI, both as TSOs and MOs, have roles defined within the draft EU regulations that the I-SEM is required to comply with. We are committed to delivering high quality services to all customers, including generators, suppliers and consumers across the high voltage electricity system and via the efficient operation of the wholesale power market. EirGrid and SONI therefore have a keen interest in ensuring that the market design is workable, will facilitate security of supply and compliance with the duties mandated to us and will provide the optimum outcome for customers.

This response is submitted on behalf of all of the EirGrid licensees.

2.2 STRUCTURE OF THE MAIN RESPONSE

Our response follows the same order of topics as presented in the consultation paper. Within each topic we address the questions raised in the text stating where we agree or not and providing justifications.

To assist the debate on the treatment of priority dispatch generation and curtailment we have included an appendix which describes the current SEM arrangements for dispatch of wind generation. While arrangements will undoubtedly change for the I-SEM, it may provide a useful frame of reference for policy considerations.

3 TREATMENT OF TRANSMISSION LOSSES

EirGrid broadly supports the proposals for the treatment of transmission losses as described in the building blocks paper for the energy trading arrangements. Given the SEMC position to retain the existing policy, we feel that the proposals set out in the paper represent a sensible approach to managing losses in the different market places.

While we agree with the proposals for traded volumes at the Trading Boundary and with physical notifications at the station gate, we believe that incremental and decremental offers into the balancing mechanism should be based on the station gate position rather than the Trading Boundary. This will maintain a consistency between the physical notifications and the balancing bids and offers which will remove the need for post processing of submissions before use in real time scheduling.

3.1 OUTTURN LOSS CORRECTION

With respect to the reference to the outturn loss factor correction, while this has been discussed further under Global Aggregation in the second phase of working groups, we note that both CER and UR have separately published decisions[1] stating that the residual volume is largely attributable to errors arising from profiled non-interval metered demand. The decisions allocate all of the residual volume to non-interval metered volume (i.e. that allocated to periods via profiles) and none to interval metered volume which may be impacted by transmission loss errors. The proposals in the consultation paper, to assign a section of this volume to forecast loss factor errors, would represent a departure from current policy. We also note that there is no well-defined process for evaluating the portion of the residual volume that results from errors in the forecasts of transmission loss factors as distinct from other causes[2]. Further investigations would be required to determine whether such a process would be feasible.

4 TREATMENT OF CONSTRAINTS

EirGrid welcomes the proposals on the treatment of constraints and the intent to maintain the current policy on constraint payments. The proposal for a potential basis for compensation by which generators may retain their inframarginal rent would appear to be a consistent means of implementing the current policy. It is also consistent with developments in the balancing market detailed design process.

EirGrid acknowledges that issues related to constraints, including the exact basis for compensation, the identification of energy versus non-energy actions, and local market power mitigation measures, will be discussed in upcoming consultations; however, it is perhaps

[1] http://www.cer.ie/docs/000344/cer11099.pdf and http://www.uregni.gov.uk/uploads/publications/Global_Settlement_Decision_Paper.pdf

[2] Other sources of residual volume are distribution loss errors, profile errors, estimated meter readings, and theft.

relevant to note that the cost of constraints under the I-SEM is likely to be greater than under the current SEM.

Under the I-SEM, constraints will result from deviations from a less granular and more blocky market position than in the SEM, which is based on a more realistic generation profile incorporating plant dynamic constraints. Market positions taken in the I-SEM ex-ante markets are likely to be less related to final physical positions than the current SEM perfect hindsight market positions, potentially resulting in less efficient TSO scheduling and dispatch decisions. Subject to local market power mitigation measures, incs and decs may not necessarily be cost based, as under the current BCOP provisions, which may be a driver for increased constraint costs. Start up costs that were not recovered through the market were previously recovered through make-whole payments; however these will now be included in the incremental cost bids, increasing the scope of the constraints costs.

5 TREATMENT OF FIRM ACCESS

EirGrid broadly supports the Regulatory Authorities' view that participation in the ex-ante markets should not be limited to capacity with firm access only.

5.1 ASSESSMENT OF NON-FIRM CONSTRAINT SETTLEMENT OPTIONS

EirGrid acknowledges benefits and disbenefits to both approaches for the basis of settlement of constraints of non-firm capacity in the balancing market. Either approach could be taken, depending on the intended primary outcome of implementing the policy.

The Ex-Ante pricing method (**Option b**) is closer to the status quo, where non-firm capacity which is constrained does not receive compensation for constrained volumes. Under this option, non-firm capacity which receives revenues in the ex-ante markets for capacity which cannot be accommodated on the system returns these revenues. However, this approach is less straightforward and more difficult to implement than an imbalance price approach, as it adds complexity by placing requirements on units to develop more complex price offers based on contracted ex-ante positions. It is also more likely to be difficult to monitor and enforce.

The imbalance pricing method (**Option a**) offers simplicity but creates the risk that the non-firm generator is either partially compensated for constraints where the imbalance price is less than the ex-ante prices or over charged where the imbalance price is greater than the ex-ante prices. Under this approach it is not guaranteed that the current policy intent will be accurately implemented i.e. the retained revenue from lower imbalance priced periods may not align with the costs from higher imbalance priced periods.

However, the signals that imbalance price uncertainty may send in terms of the lower value of non-firm capacity may feed through to changes in participant interaction with the market. For example, units with non-firm capacity may be incentivised to take their potentially constrained volumes into account in the market, adjusting their positions in the ex-ante markets if they deem it likely that the system will not be able to accept this capacity. This could result in the ex-ante market outcomes becoming closer to what is required for a feasible dispatch, and places a greater incentive on this capacity to be balance responsible. Taking such an approach would allow participants to avoid exposure to the imbalance price under constraints, while retaining the potential to earn revenue for non-firm capacity when it can be accommodated on the system through balancing market participation.

5.2 PROVISION OF CONSTRAINT INFORMATION BY THE TSO

It is acknowledged that compelling, or encouraging, non-firm capacity which is likely not to be accommodated on the system to trade out in the intraday market (**Option c**) is not a standalone option. It is also not likely to be an option which can be facilitated by the TSO to the extent proposed. It would not be possible for the TSO to give a guarantee that they will constrain units at a unit level of granularity, as the decisions taken to manage a constraint are normally in a much shorter timescale than can be accommodated in the intraday market, e.g. in the scale of minutes rather than hours. Firm access allocation is not carried out in a dynamic way and the TSO does not currently consider firmness on a real-time basis or for economic scheduling purposes[3].

However, it is possible that participants would be able to deduce when they may be constrained from information available to them through the market. For example, if they can see in the balancing timeframe in a particular hour that they are being constrained down from their cleared day-ahead and intraday market positions, using aggregate market information provided they could deduce the likely levels to which they would be constrained in the following hours and may take appropriate actions in the intraday market.

The possibility that the TSO could provide more general, qualitative information about constraints could be further explored, however it should be noted that the ability of market positions to change right up until an hour ahead of real time would make constraint forecasting potentially unreliable.

An additional consideration, not raised in the consultation document, is the interaction between firmness and curtailment. If the preferred option for the settlement of curtailment allows for the possibility of compensation, i.e. if there is the potential for priority dispatch units to receive revenue for curtailed volumes, this could reopen the consideration of the relationship between firmness and curtailment.

Overall, EirGrid's preferred approach is **Option a**, the imbalance price approach, on the basis that it offers simplicity and the potential to strengthen balance responsibility and generator locational signals. In our view these benefits are likely to outweigh the concern that the current policy on compensation would not be implemented in all periods.

[3] However the TSO does take firmness into account in specific situations when managing tie-breaks in constraint groups where non-firm wind would be reduced first.

6 TREATMENT OF PRIORITY DISPATCH

To provide some context on EirGrid's views around treatment of Priority Dispatch, we have included an appendix to this paper, [Wind Dispatch in the SEM](), which explains how wind generators are currently controlled by the TSOs as part of system operations. In addition, although much of the discussion focuses on intermittent wind generation, the treatment of Priority Dispatch should be technology neutral, for example to include emerging intermittent solar generation as well as peat-fired thermal generation.

A suite of applications accessing a variety of data are used currently by the TSOs to manage wind energy on the system. These have been developed to implement the Regulatory decisions on the treatment of Priority Dispatch generation in the SEM while enabling the TSOs to fulfil their obligations to operate the system in a safe, secure and efficient manner.

The main characteristics are as follows:

- Normally wind units generate to their available level without being issued a dispatch instruction but may be required to "dispatch-down" for reasons of curtailment and constraint;
- Dispatch-down of windfarms is achieved by remote control initiated from the control centres when the TSO sends a maximum MW setpoint to (automated) wind farm control units as most windfarms are not staffed to accept dispatch instructions and control output accordingly;
- In curtailment events setpoints are issued (simultaneously) to all controllable windfarms, and in constraint events to relevant subsets of windfarms. The TSOs only currently deal with a small number of groups of windfarms based on specific categories, rather than each of the numerous windfarms individually.

In this context, EirGrid has put forward a suggested approach, considering the proposals presented thus far and additional factors, on how priority dispatch could be accommodated in the I-SEM.

6.1 CONSULTATION PAPER PREVIOUS APPROACH

Three options were put forward in the consultation document for an approach to enacting price taking in the balancing market:

- A price based approach where price taking generation are mandated to submit an order price at the notional price floor of the market, for example -€500/MWh.
- A price based approach where price taking generation are mandated to submit an order price at €0/MWh.
- An explicit mechanism which is not price based.

The first and third options offer an explicit price taking approach. While in principle having a zero order price for priority dispatch is not undesireable, it means that these units are no longer price taking. If the market price floor is below €0/MWh, then they are stating a price level below which they are no longer willing to trade in the market. This could lead to situations where, for example, a thermal unit may wish to remain on overnight for technical reasons and offer a negative price to do so, meaning that economically they would be in the merit order ahead of zero priced priority dispatch units.

This would point to the need to not restrict priority dispatch units to a particular price level, leaving them free to submit commercially desired order prices. While not strictly a matter for market design, when considering that there exist different levels of renewable supports and that different units are covered or not by such supports, this points towards the need for the design to facilitate different price level submissions by participants.

This would represent a change to the operation of the system and the approach to the dispatch hierarchy, tie-break and pro-rata dispatch-down. It would require dispatch solutions such as a more sophisticated economic dispatch system, potentially moving towards automated dispatch and automated generator control (AGC) to handle the large increase in the number of discrete units to be controlled individually, as opposed to the current treatment of wind units in groups based on a small number of categories.

However, an economic price based approach could be beneficial. It allows for consistency between the day-ahead, intraday and balancing markets, and would allow for a more straightforward interpretation of the interaction between price taking and priority dispatch. Under this approach, if a unit is priority dispatch, it must agree to be a price-taker and take any price arising in the market by submitting an order price at the price floor. If a unit wishes to be a price-maker by submitting a different order price, it is electing to forego priority dispatch and may be dispatched down by the TSO on an economic basis.

6.2 CONSULTATION PAPER REVISED APPROACH

The consultation puts forward an additional revised approach, based on the submission of physical notifications and inc and dec orders. This approach appears to be overly complex and differs from the way that wind generators are currently controlled on the system. For this approach to work, active participation from the priority dispatch units would be required, including from small wind players. The revised approach may require a controller at each unit to hold the windfarm output at the submitted physical notification level, or to receive an instruction to increase or decrease their output and perform this action if the TSO requires an inc or dec from the unit. Their compliance with this instruction would then be subject to the same conditions as all other generators in imbalances.

It would also potentially require two dispatch scheduling tools to be used in different situations, and a complex interaction between them in terms of when each should be used and how to transition between the tools. For example, in situations where wind unit notifications reflect their availability and there is no system requirement to dispatch-down the units, the wind dispatch tool[4] which does not take price into account should be used as the most effective tool for that situation. However, in situations where there is a requirement to dispatch-down and therefore take price into account, an economic dispatch tool would be required.

The revised approach potentially does not interpret priority dispatch correctly – it is difficult to see the difference between a priority dispatch unit giving prices and volumes for deviation from a physical notification which must be the start point for the dispatch, and the process undergone by non-priority dispatch units for physical notification and balancing market orders. Stating that you are willing to deviate from a priority dispatch level removes the priority from that level.

6.3 ALTERNATIVE EIRGRID PROPOSAL

The options for treatment of priority dispatch in the consultation merit discussion but there are potentially other alternatives given the diversity of the wind portfolio in the I-SEM. While the consultation proposes price based solutions requiring all wind generators to submit decremental prices with their notifications to the TSO, this may place an undue level of administrative burden on certain generators. We think that the solution for the I-SEM should take account of smaller generators and still retain a price-taker option.

A priority dispatch generator can elect to act as a price-taker in the following manner:

- The generator would submit no notifications to the TSOs[5], who would instead use real time monitoring data to track the generator's output. Because the generator has not submitted any incremental or decremental prices, this means that in the event of being dispatched down the generator can be cashed out at the imbalance price.
- Where there is no dispatch-down, the generator would be settled at the imbalance price if their only activity is to spill into this timeframe. This does not preclude a generator in this scenario from trying to maximise their revenues by contracting in the day-ahead or intraday markets in which case the residual would be settled at the imbalance price.

Generators who wish to be more active in the balancing timeframe can follow a version of the proposal in the consultation paper.

- These generators can submit a notification to the TSOs with a decremental price to represent their cost for being dispatched down from this point. The notification can be based on contracted positions from the day-ahead or intraday markets, or represent a desired volume to spill in real time.
- The TSO would not attempt to hold the generator exactly at their nomination but would permit the generator's output as the secure operation of the system permits. In the event that the generator is dispatched down, this could be treated as a constraint and

[4] See Appendix.
[5] While this crosses over with some of the discussions on physical notifications covered in the Market phase, it is relevant here also.

they would be settled at their decremental price (or imbalance price if higher).

- Any deviations from the notification would be treated as imbalance and settlement would be at the imbalance price.

We believe requesting incremental bids from wind generators may be problematic. A wind generator with a notification and incremental bid implies that the generator is self-curtailing and offering in a lower volume while being capable of delivering a higher one. However, if the TSO activates the incremental bid, this impels the wind generator to produce this higher volume in full. In the event that there is insufficient wind available, the generator will be exposed to imbalances for the delta.

Under this approach, the priority dispatch status of a unit gives them the right to choose to operate with priority dispatch if they agree to be a price-taker, or the right to operate as a price-maker with priority determined on an economic price-based basis (as they are actively agreeing that their output can be reduced by submitting a nomination and decremental price). This choice is enacted through the participant's interaction with the balancing market, rather than through a change in status. However, the impact this approach could have on the operation of the system and dispatch tools (e.g. should units decide with regularity to switch between being a price-taker and price-maker) would need further examination.

We view an approach with units being purely priority dispatch price-takers or non-priority dispatch price-makers as the preferred approach.

6.4 LATE UPDATES OF PHYSICAL NOTIFICATIONS

With regard to the proposal that priority dispatch generators could be allowed to update their physical notifications after the intraday gate closure, the benefit of such an approach is not immediately obvious. The units would not be able to update their commercial characteristics after intraday gate closure; therefore, the sole purpose of this would be to guarantee this notification as their priority dispatch price taking level in the imbalance settlement. This is only relevant if the TSO replaces the current method of running wind units based on availability to basing their running on the physical notifications. This is a large change to the way in which wind units are currently controlled, presenting not insignificant challenges for both the control centres and the participants in question. For participants, they would be expected to control their output according to dispatch instructions based on their discrete physical notifications, as opposed to operating according to availability until such a time as they are required to limit their output for system reasons.

It could result in problematic situations where, if the control of the wind units is retained by the control centre through the use of the wind dispatch tools, physical notifications at discrete values would represent an implicit request not to spill any additional power onto the system which would be considered an imbalance. This would require the control centre to control the output of wind in a different way than it currently does through the power-limiter function.

This may be of benefit in scenarios where, for example, a wind unit has a better wind forecast for their unit than the TSO, and they preferred to feed through the most up-to-date information on the availability of the unit. This information may then be of use to the TSO for making the best dispatch and scheduling decisions possible. However, this information does not have to be given to the TSO in the form of a physical notification. For example, like forced outages, a separate information channel could be a better solution.

An additional consideration is the ability of the TSO to receive and incorporate these late physical notifications into its dispatch processes and systems. The difficulties of implementing this may outweigh the perceived benefits.

6.5 ABSOLUTE PRIORITY DISPATCH

As with the views shared on the price-taker aspect of priority dispatch, absolute priority dispatch could also be enacted and interpreted on an economic basis. Negative prices and the acceptance of such prices should not be ruled out; these may provide an incentive for priority dispatch plant to be balance responsible, and to try and match their expected operating levels as reflected in the ex-ante markets as accurately as possible. If an economic basis for priority dispatch is in place, it follows that demand would not be accepted when it does not make economic sense to do so, and so if negative prices result from accepting demand, it must be the most economic approach. An equitable approach for both generators and demand should be in place in terms of a market price floor and cap.

7 TREATMENT OF CURTAILMENT

As with priority dispatch, although much of the discussion focuses on curtailment of intermittent wind generation, the policy should be technology neutral, for example to include emerging intermittent solar generation.

There are three options put forward for the means of implementing the SEMC decision on curtailment compensation post-2018 (SEM-13-010):

- Mandated bidding behaviour, where generators are required to bid a decremental price based on revenue in ex-ante markets;
- Cash out any deviations due to curtailment at the imbalance price as if it were a normal imbalance from a market position;
- Cash out any deviations due to curtailment at the imbalance price, but then have a post-processing “make-whole” procedure which takes into account revenues received from ex-ante markets (i.e. if the imbalance price is less than the day-ahead market price, the day-ahead market revenue should be recouped. If the prices are the other way around, the unit should be compensated for the over-recovery through the imbalance price).

7.1 ASSESSMENT OF OPTIONS

As discussed in the firm access and priority dispatch sections, mandating generators to bid decremental prices reflective of their ex-ante revenues is relatively onerous and cumbersome especially for small players.

The second of these options does not appear to align with the SEM-13-010 decision, as it allows for generators to potentially retain ex-ante market revenue for curtailed volumes where the imbalance price is less than the prices achieved in the day-ahead or intraday markets. However, the lack of a guarantee that the imbalance price will be higher or lower than the prices in the ex-ante markets in some hours could offset this. This depends on the shape of the imbalance price which in turn depends on which generators participate in which market. If wind decides to not participate in the day-ahead market, in hours of curtailment it may be that the imbalance price could be lower than the day-ahead price, or even negative, owing to the relatively large volumes of cheap wind normally accompanying hours of curtailment. In these scenarios, wind generators would retain the difference between ex-ante prices and the imbalance price for curtailed volumes. It is possible that wind generation might have a perverse incentive to take market positions, when curtailment is expected, in order to exploit this effect.

The third option would remedy the problem of the second regarding compensation but would require additional settlement functionality as well as a high level of information sharing across market timeframes. This option would have the undesirable effect of removing such generators from exposure to the imbalance price and potentially dampening the balance responsibility incentive.

However, an approach using the imbalance price could be preferable. Such an approach would be consistent with the pricing of other balancing market actions.

There is a potential that exposure to the imbalance price may incentivise balance responsibility, possibly leading to units considering potentially curtailable volumes in their ex-ante market trades. For example, with access to sufficient market information, an assessment could be made of when it is likely that they will be curtailed (based on, for example, aggregate wind forecast, demand forecast, interconnector flows, etc.). They could then trade in the ex-ante markets to exclude the potentially curtailable volume, either by not including this volume in their day-ahead market order or through buying back the portion of a cleared day-ahead market position related to potentially curtailable volume in the intraday market. This has the potential to decrease the cost of the balancing market, as the ex-ante markets should be closer to a feasible dispatch of the system, requiring fewer actions to be taken in the balancing market.

In summary, EirGrid believes that the cash out at the imbalance price without post processing offers the best solution since it is less complex and largely reinforces the correct incentives.

This is related to the question raised in the consultation paper of whether day-ahead and intraday market volumes should be treated differently from balancing market and imbalance volumes under the curtailment post-processing option. It is suggested that different treatment as proposed leads to the second option of cash out at the imbalance price without post-processing for the day-ahead and intraday market volumes. However, as stated previously, settlement at the imbalance price would result in times where participants pay back less or more than their earned revenues. Therefore both approaches using the imbalance price treat day-ahead and intraday markets the same as the balancing market volumes in that revenue earned for curtailed volumes is recovered. The inclusion of a post-processing solution merely affects the extent to which this recovered revenue is equal to the revenue earned in the day-ahead and intraday markets.

8 DE MINIMIS LEVEL

While EirGrid supports the retention of a de minimis level no higher than the current level, we would support consideration of changes to the de minimis level for mandatory participation where the value takes account of the current Grid Code requirement for controllability, i.e. 5MW. This would help strengthen the link between units participating in the balancing market and units subject to control.

Given that a lot of the smaller generation is connecting to the Distribution System and given the forecast increased need (with greater wind penetration) to control such generation on the DSOs' systems, there is likely to be a need to further formalise relationships between the TSOs and DSOs with possible changes required to the Distribution Code.

We would support the inclusion of a minimum threshold for market participation. One potential driver for this would be around the practicality of interacting with the European market systems. The systems mostly work to a rounding granularity of 0.1MW for submitted volumes, meaning that there will be an implicit limit in these systems with which it would be worth aligning the balancing market. There is also a potential driver from a dispatch perspective, where there would be a significant challenge for the control centres to increase their scope of controllability to cater for the large number of units at these smaller values. It would not be economic to set up arrangements to dispatch small units.

We would suggest this value also takes account of the Grid Code where, in section OC10, there is a current requirement for units to be at least 4MW to be subject to central dispatch by the TSO. This would help strengthen the link between balancing market participation and controllability, so that situations cannot arise where balancing market interactions require controllability which is not provided for within the Grid Code.

With regard to aggregators, there is the potential for system control issues if aggregators are allowed to have wind units with a Maximum Export Capacity (MEC) in excess of the de minimis level. At such higher capacity levels, access to local granularity of expected output as opposed to a portfolio submission covering a number of areas would be required. In the current SEM, no Aggregated Generating Unit can have a sub-unit ≥ 10MW on any site.

While the HLD Decision stipulates that current arrangements such as supplier 'lite' will continue, it is difficult to envisage how these arrangements can persist unchanged given the nature of the European arrangements. The term supplier 'lite' has come to refer to the circumstance where a participant registers a supplier unit in the SEM with minimal demand included but with an amount of below de minimis generation embedded. This generation appears as a negative demand value in the SEM and is settled using demand prices as applicable. This concept is not compatible with the European day-ahead market which is based on providers of energy offering to sell and consumers of energy bidding to buy. In other words, under the I-SEM model, where a participant has used a supplier 'lite' to embed generation, this must be represented in the day-ahead market as an offer to sell energy just as a normal supplier unit is represented as a bid to buy energy. How these are represented in the balancing market, particularly if there is an obligation to submit physical notifications with incremental and decremental prices, needs to be explored as it represents a different approach to that currently used in the SEM and therefore needs to be fully understood by participants.

9 TREATMENT OF CURRENCY

EirGrid welcomes the proposals on management of currency cost as set out in the consultation paper. The current arrangement where currency deviation is measured by calculating the exposure of all transactions before netting these and socialising across all participants has proved overly complex and opaque. This has resulted in onerous workarounds, re-settlement of currency costs to correct errors, and ultimately in modifications to the Trading & Settlement Code.

The proposal to forecast the discrepancy one year ahead and manage this through a tariff would deliver a more straightforward process for participants, who will have sight of how the tariff is set and who will be able to budget accurately and better incorporate these costs where required. We believe that the proposed approach should be considered across all I-SEM revenue streams, i.e. the day-ahead market, the intraday market, balancing and imbalance settlement, and the Capacity Remuneration Mechanism.

Given the faster settlement timeframes that are envisaged for the day-ahead and intraday market positions, and that the day-ahead and intraday markets will not be subject to revisions at Month+4 and Month+13, it is likely that exposure to currency fluctuations will be significantly reduced in the I-SEM from that experienced in the SEM, and that the overhead will be reduced. While the overall annual net currency cost / benefit may be small (generally due to faster settlement cycles and opposing fluctuations netting), there could be material exposures over shorter timeframes (e.g. in balancing) for which the relevant settlement entities will need to provide working capital.

The approach to determining the currency cost or benefit will need to be considered for each timeframe in the I-SEM as the exposure may be derived from different volumes in each. For example, as proposed in the consultation paper for the day-ahead market, aggregate contract positions across each jurisdiction can be used to determine the jurisdictional imbalance. This will determine what volume of contracted production from one jurisdiction served contracted consumption from another, thereby representing a virtual export and, hence, the volume of energy which is subject to currency fluctuations. This approach could also be used for the intraday market. However, for the balancing timeframe, non-energy actions which are expected to be funded through an imperfections price approach may need a different mechanism to determine the cost.

We also believe that the tariff based approach should be considered with respect to the Capacity Remuneration Mechanism, assuming that here a dual currency approach will also be adopted; however, more consideration needs to be given in this workstream given the potential variances in exchange rates over longer periods of time.

However the following issues need to be considered which may affect the policy decision or the implementation of the policy:

- How feasible it is to forecast the change in relationship between the Euro and the GBP: the experience over the last year did not tally with expected forecasts. While this does not matter so much for a small volume of cash flows, it may start to have an impact if volumes begin to increase. Using the forward market currency rates at the time of determination may be an approach that removes subjective judgements.
- How is it decided who is a "supplier" on whom this is levied (e.g. is a bid to buy seen as a "supplier" trade? Is the designation of "supplier" based on unit registration? How are assetless traders treated?).

10 MARKET INFORMATION

EirGrid is supportive of proposals to maintain a high level of transparency with respect to market data. Transparency should be considered as a minimum to be at the same level considered in Europe and as prescribed by the Network Codes and pertinent Transparency Regulations, but on a case-by-case basis it should be determined whether a higher level of transparency at which a particular item of data should be published should be considered. With some types of data being more transparent than elsewhere in Europe there is potential for I-SEM participants to be disadvantaged versus participants in less transparent markets. However, higher levels of transparency on particular items of data could be a key market power mitigation tool if suitable.

EirGrid is also supportive with respect to potential additional publications that should be made available to the market, including but not limited to wind forecasts, demand forecasts, aggregate notifications, aggregate day-ahead and intraday contract volumes, aggregate price curves of balancing incremental and decremental offers, etc. It is very important that participants are not only incentivised to be balance responsible but also that market information facilitates this responsibility. With this information, suppliers may be able to determine their potential exposure to imbalance prices (using the aggregate contract volumes with the demand forecast and the aggregate price curves of balancing bids) while they still have the opportunity to adjust their positions in the intraday market at potentially better prices.

While we note the suggestion of developing market systems that have the capability to publish as much information as possible, this needs to be considered against the implementation cost involved. It should be noted that where the consultation paper considers that for the balancing market design there will be less influence from the EU marketplaces, it will be necessary for our balancing arrangements to anticipate and comply with the Network Code on Electricity Balancing, some provisions of which will come into force by I-SEM Go-Live.

A notice board is also considered a good idea, but effectiveness of this facility would depend on its implementation. For example in other markets, participants are allowed publish different kinds of information on different facilities, including their own websites, market noticeboards and elsewhere. It is worth considering how a single centralised facility, incorporating different media channels, could be implemented, building on the themes to be further developed throughout the market design process, to deliver the required information in the most efficient, timely, and practical way.

A fundamental requirement of the I-SEM is compliance with new regulations and network codes. EirGrid is currently undergoing a process to ensure that all requirements are taken into account, including seeking legal advice on the obligations for publishing information arising from these new regulations. These will be important considerations in the design and implementation of the new I-SEM systems and services.

11 APPENDIX: WIND DISPATCH IN THE SEM

Numerous tools and inputs are used by EirGrid and SONI TSOs to manage wind energy on the system in the TSOs' control centres, including the Wind Security Assessment Tool (WSAT), the Wind Dispatch Tool (WDT), Wind Energy Forecasting (WEF) and SCADA data feeds from wind units, and the Energy Management System (EMS). The management of wind energy is also subject to a number of processes and rules including e.g. the definition of constraint and curtailment conditions and regulatory rules for tie-breaks. This section aims to give a brief outline of how wind energy is currently managed on the system, to provide a frame of reference for the discussion on various aspects of the Building Blocks consultation.

In general wind units currently generate to their available level, without being issued a dispatch instruction of a level to which they must track their generation output. There are however certain situations where wind units may be required to "dispatch-down", namely for reasons of curtailment (system situations) and constraint (local network situations).

On 26 August 2011 the SEM Committee published its decision on the "Principles of Dispatch and the Design of the Market Schedule in the Trading and Settlement Code" (SEM-11-0621). The key message in SEM-11-062 is that the TSOs should continue to "adhere to an absolute interpretation of priority dispatch whereby economic factors are only taken account of in exceptional situations". On 18 November 2011, EirGrid and SONI published a list which placed wind units in the order in which they would be dispatched down by the TSO in the event that there is a surplus of generation and priority dispatch units need to be dispatched down. Three categories were described in this list.

In general wind units are dispatched pro-rata in a hierarchy order according to their category. Wind units belong to one of 3 categories:

- Level 1 Units (Should be controllable but cannot be controlled);
- Level 2 Units (Should be controllable and can be controlled);
- Level 3 Units (Not required to be controllable).

A deviation from this is for wind units in specifically defined Constraint Groups. In these areas, for reasons of constraint in tie-break situations, the priority order also takes into account the firmness of the individual units.

WSAT is a tool in the TSOs' control centres which calculates the Secure Wind Level (SWL) on the system on-line by modelling thousands of static and dynamic contingencies using real-time network topology and operating conditions as a starting point. At present SWL is defined by the voltage stability limit of the system assessed through analysis of a transfer between wind and conventional generation. In future SWL will also take account of thermal, transient, and frequency stability of the system with changing wind penetration. The outputs from WSAT support decisions of the Grid Controller with regards to dispatch of wind generation through the Wind Dispatch Tool.

The Wind Dispatch Tool (WDT) application is a component of the Energy Management Systems

(EMS) used in the TSOs' control centres. While the TSOs currently manage controllable wind farms via separate Wind Dispatch Tools, these will be integrated under the on-going EMS Upgrade Project. This will result in the delivery of a single WDT with the capability to dispatch all controllable wind farms on the island.

The fundamental function of the Wind Dispatch Tool is to issue MW setpoints to wind farms when it is necessary for the TSO to control active power output. The TSOs can enter a target MW value for a group of wind farms; the WDT will then calculate individual setpoints to be issued to wind farms. There are two types of dispatch setpoints issued by the tool:

1. Curtailment: Curtailment setpoints are issued to all controllable wind farms in response to a system-wide issue e.g. high System Non-Synchronous Penetration.
2. Constraint: Constraint setpoints are issues to subsets of wind farms to resolve local issues to which they are contributing e.g. to alleviate congestion on a particular transmission line.

During the time period where the setpoints are in place, a wind farm is prohibited from exceeding the MW setpoint issued to it by the Wind Dispatch Tool. However, a wind farm's output may reduce significantly below that value, e.g. if wind availability reduces. The setpoint is effectively a cap on output rather than a MW target. Once the system-wide or local issue has been resolved, the TSOs will remove the curtailment or constraint by dispatching the relevant wind farms back to maximum available output. It is also worth noting that constraint and curtailment can be active simultaneously, resulting in a more complicated "nested" dispatch scenario.

The Wind Dispatch Tool also provides functionality for the following:

- Wind farm dispatch testing;
- Category 1 wind farm dispatch and disconnection;
- Wind farm frequency control settings.

These systems and tools have been developed to comply with the various Regulatory decisions on treatment of priority dispatch generation in a way which allows the TSOs to deliver their obligations to manage the transmission system in a safe, secure, and efficient manner. These include the obligation to maximise the output of renewable generation subject to the system's ability to accommodate it and not to unfairly discriminate against any particular windfarms under curtailment conditions.

Currently the Wind Dispatch Tool takes no account of price information in determining the levels of dispatch for wind farms. Consequently some of the proposals put forward in the Building Blocks Consultation would require redesign of the Wind Dispatch Tool or integration of its functions within a Security Constrained Economic Dispatch (SCED) module.

Dispatch of windfarms is via remote control from the TSOs' control centres, as most windfarms are not staffed to accept dispatch instructions and control output accordingly. Consequently new proposals also need to consider the potential impact on market participants.

The tools, processes and structures explained in this section highlight the fact that the dispatch and control of wind on the system is very different to the way it is currently performed for conventional generation.