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Dear Sir/Madam

Re: Consultation Response to SEM 09 073 - Principles of Dispatch & Design of Market Schedule in the Trading & Settlement Code

This submission is made on behalf of RES UK and Ireland Ltd and RES Ltd, which form part of the RES Ltd group of companies. RES has been developing wind projects on the island of Ireland since the early 1990s, having developed eleven operating wind farms in Northern Ireland and four in the Republic of Ireland.

We thank you for the opportunity to comment on this consultation. If you have any queries about any of the points raised, please do not hesitate to contact me.

Support for IWEA Consultation Response

RES would like to register its full support for the IWEA response to this consultation, which has engaged significant technical, economic and legal input from IWEA members, supplemented with input from Pöyry Energy Consulting and Eversheds O'Donnell Sweeney.

Allocation of Access Rights (Section 4.5)

Section 4.5 of the consultation document discusses a number of options for amending market payments to accommodate perceived inefficiencies with the allocation of infra marginal rents in the event of transmission constraints.

RES does not agree with the arguments set out in the consultation document. RES believes that the current SEM rules are robust and continue to provide appropriate economic signals in the event that transmission constraints exist on the system.

An example of potential inefficiencies is set out in Box 2 of the consultation document. In this example, two generators, G1 and N are connected on the export side of a transmission constraint boundary and a further generator G2 is connected on the import side of the same constraint boundary.

In the example, G1 and N are scheduled whilst (due to the constraint) G2 and N are despatched. As a result there is a constraint cost calculated by the difference in bid prices between G2 and G1 (P2-P1) multiplied by the constrained volume V2=V1.

However, this does not take account of the fact that the introduction of generator N has reduced the SMP. Since SMP was previously set by G2 (SMP = P2) and will now be set by G1 (SMP = P1) there has been a saving to consumers calculated by the difference in SMP (P2-P1) multiplied by the total volume of demand. Since, the reduction in SMP is (by definition) greater than the constraint cost, the consumers benefit from the introduction of new generation even in the presence of a transmission constraint

It is also noted in the consultation document that G2 will (whilst the transmission constraint is active) only receive its bid price and so may lose money unless it is a BNE Peaker plant. This is true. However the corollary that all new generators on the import side of a constraint boundary will all be BNE Peakers is patently incorrect. The incentive for connection of new generators is the same whether or not the transmission constraint is active. New generation is incentivised to connect if its bid price is lower than G2 and it will displace G2 both in the Schedule and in despatch.

The net effect of a transmission constraint is to create a transient reduction in efficiency in market payments. This effect lasts until either the transmission constraint is removed (perhaps by the building of new transmission assets) or until further new generation connects on the import side of the transmission constraint and displaces the constrained on generator (G2). The cost allows for the temporary continued dispatch of a generator (G2) that would otherwise have closed. This constraint cost is less than the saving to customers created by the reduction in SMP. In addition the constraint cost provides a valuable market signal in its own right as it effectively creates a value for the introduction of new transmission assets.

The options proposed in the consultation document attempt to create additional income for the constrained on generation but in doing so set SMP to a higher level than would prevail under the current market rules prevent consumers and thus deny customers the benefits of increased competition in the generation market.

RES notes the argument that some generation may find itself constrained on but unable to cover its full operating costs. RES believes that it is more efficient to, if necessary, provide additional targeted compensation directly to such generators rather than attempt to achieve the same ends by manipulating market prices.

In summary, it is our view that the existing market payment mechanisms are appropriate, without amendment, whether or not the transmission network contains constrained boundaries.

Finally we would add that continued new investment requires stability in the market arrangements. To make fundamental changes to market rules so early after the introduction of the SEM will reinforce the perception of investors that there is “regulatory risk” and suggest that there is uncertainty in predicting future market behaviour. Since institutional investors charge a premium for uncertainty, the proposed changes may lead to reduced future investment and reduced competition in generation, which would be to the detriment of consumers.

Priority Dispatch (Section 4.8)

Absolute priority

We do not believe it would be feasible that wind or any other renewable generator should have absolute priority dispatch. The implications of this would simply be too impractical and costly.

Qualified dispatch

Option 2(a): Dispatching purely on economic merit

RES is concerned that this approach would send out the wrong market signals as it may incentivize the building of generation plant with high start-up costs. As we understand the option, the net cost created from the start-up costs of a de-committed generator converts in to a negative SMP. The SMP goes negative because an increase in demand would cause a reduction in costs.

As generators with priority dispatch will lose money if they generate during these times of negative pricing they will not generate and the conventional plant will generate instead. This would incentivize the building of generation with higher start-up costs.

High start-up costs are the opposite of what the SEM will require if it wishes to minimize electricity costs to consumers and increase its installed wind capacity. Both NI and ROI have high renewable electricity targets, which will be largely be fulfilled by wind. In order to create a cost effective electricity network with high levels of wind capacity, flexible plant that can ramp up and down at low cost will be essential. Market rules should be established that incentivizes the building of flexible plant that will serve the long term interests of the market.

Additionally, it could be argued that this option offers no priority to wind generation. In this option when wind is not economic it will not be dispatched in favour of conventional generation because wind generators will not want to pay the negative prices, and the only time it is dispatched is when it is economic to do so. How does wind have any ‘priority’ status in this situation? How does wind have any more or less priority than any other plant when it is purely economic principles that dictate the market?

Option 2(b): Priority Dispatch in tie-break situations

This option is an extension of the option 2(a) which we have concerns about, these concerns apply to this option also.

Option 2(c): Dispatching taking into account subsidies

Firstly the suggestion that this option would double count carbon costs is irrelevant. The discussion under question is about EU requirements for priority dispatch, not how carbon cost should be captured. Even so, it is unfair to suggest that carbon costs would be double counted as the social cost of carbon is far higher than the price of carbon emissions permits.

This option may be good way of running the market. Bidding the opportunity cost of subsidies will enable an economic mechanism for renewables to establish priority over conventional generators. However the hierarchy of priority based dispatch will unfairly disadvantage generators in ROI.

Option 2(d): Dispatching at some other effective price

This option would provide a clear and simple way of establishing when renewable generators and conventional generation should be dispatched. This system would give NI and ROI projects an equal position within the market. Potentially the effective price set could be used to influence investment decisions. A potential problem is that generators with start-up costs high enough to surpass the effective price will be rewarded by higher generation. However, this system would not disincentivize the building of flexible plant.

General comments on priority dispatch

Any changes made should only apply to new plant being built. Our existing wind farms are financed based upon the assumption of priority dispatch, if we cannot generate all of our electricity, revenues may fall and we could potentially default on our loans.

Current support mechanisms are based upon current priority dispatch practices. A revision to this may halt wind development in the SEM if revenues fall. A situation that should be avoided is a mismatch between subsidy mechanisms and market operation whereby the market mechanisms leave the subsidies inadequate for the support of the technology.

If additional costs are created from priority dispatched they should not be levelled upon the renewable generators individually but across all generators in the market. Levelling costs upon renewable generators will prove a zero-sum exercise as these generators will require larger subsidies to pay the increased costs.

The example provided in section 4.8 is poor as it is too much of an all or nothing situation. Variances in wind generation should be accommodated by a reduction in output across all conventional power stations rather than by individual stations. If a situation occurs where a generator needs to be switched off it may prove more economic to constrain down wind, however wind will need to be compensated for this loss of output as current projects are financed upon the existing principles of priority dispatch.

Treatment of Variable Price-Takers (Section 4.8)

Scheduling VPT generators based upon availability provides certainty in the size of the Market Schedule Quantities (MSQs) for VPTs. This provides a stable platform from which future revenue streams can be forecasted which enables accurate calculations of the value of investments. This is essential for financing projects.

Any revision to the treatment of VPTs must provide certainty in the MSQs for VPTs. This will ensure that an accurate measure of the value of projects can be calculated, enabling financing.

Yours sincerely,

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