Market related issues for renewable electricity in the Republic of Ireland

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14th April 2011

Introduction

The All-island Single Electricity Market (SEM) is a relatively new electricity market, covering the whole of the island of Ireland, having gone live on Nov 1st 2007. The overall authority of the market, known as the SEM Committee, began reviewing the rules relating to wind in particular within 4 months of the start of the market, publishing four major papers[1]. It has yet to reach a conclusion, and since this has taken much longer than anticipated, it has created considerable uncertainty in the whole market, in particular for wind generation.

Decisions by the SEM Committee on these issues continue to be delayed, but again, a key decision is currently expected next Monday, April 18th, though a further delay could be anticipated.

The original intent of the process appeared to be to deviate from priority of dispatch for renewables, at certain times, for example during excess generation events, so that they would receive no payment when not run. Following strong interventions by the industry on priority of dispatch, based on legal interpretations of the RES Directives, the proposal was changed. It moved towards excluding renewables from the Market Schedule (or the proposed dispatch, done 24 hours ahead in the SEM), as deemed necessary, so that when dispatched off, no payment would be received. In other words, not only would wind be dispatch off for network stability reasons, which is allowed under the Directive, but they would also receive no payment whatsoever in those situations.

The wind industry would not insist on being dispatched in a way that would destabilize the system, as this would be both counterproductive and contrary to the RES Directives. The issue is that renewables are guaranteed transmission under those Directives, and where the authorities have failed to take measures to realize that guarantee, over nearly 10 years, then they ought not to compromise the economics and even the viability of renewable projects because of their own lack of compliance.

However, if the decision follows the current line of thinking, we can more or less forget about electricity generated from renewable energy sources in Ireland,

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[1] Single Electricity Market, "Wind Generation in the SEM, Policy for Large-Scale, Intermittent Non-Diverse Generation" Discussion Paper, SEM-08-002, 11th February 2008; "Principles of Dispatch and the Design of the Market Schedule in the Trading & Settlement Code, A Consultation Paper", SEM-09-073, 8 July 2009;
Single Electricity Market "Principles of Dispatch and the Design of the Market Schedule in the Trading and Settlement Code" SEM Committee Proposed Position Paper and Request for Further Comment, SEM-10-060, 2nd September 2010;
"Monitoring the Divergence of the Market Schedule from Dispatch and the Impact on Consumers" Consultation Paper, SEM-11-002, 18 January 2011.

maybe even on the island as a whole. The imminent decision therefore has the potential to completely derail achievement of Ireland's binding RES targets.

There is overlap between discussions about the Republic of Ireland, and its policies and targets, and the all-island SEM, part of which falls under the UK's jurisdiction and its targets. This paper will focus on the Republic, as affected by the All-island SEM.

Constraint and Curtailment

Loss of generator output due to local transmission blockages (called constraint) is quite common throughout the EU, and affects all generation types. General system-wide curtailment of renewable generators (due to inadequate demand/excess generation, or inertia on the system, for example) is likely to arise in all EU Member States at some stage. But it is already happening in Ireland on a small scale, according to the System Operator - wind reached the 50% limit in April 2011 and was apparently curtailed. As a lot more wind connects in Ireland, this is likely to become a major issue quite early. There are three basic reasons why this will become a major issue in Ireland soon:

1. Ireland has exceptional renewable resources, particularly wind, well beyond its own needs, while having small amounts of peat and gas from which to secure its energy supplies at reasonable cost, and has thus set a very ambitious 40% renewable electricity target; enough capacity to meet that target, and a lot more besides, is in development.

2. On the other hand, Ireland's grid still has only very limited interconnection - the Moyle DC link, accessed through AC links with Northern Ireland, which are being strengthened; and Ireland will soon have a small 500MW DC link with Wales; however, exports are not anticipated by the System Operator on either link, for market regulation reasons; also these DC links are not expected to provide the sort of inertia the System Operator needs; so while it is being strengthened internally, the All-island network is and is likely to remain very isolated compared to other networks around the EU.

3. Despite the grid obligations arising under the 2001 and 2009 Renewables Directives[2], and continuous reminders about those obligations[3], Ireland has not

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[2] the 2009 Directive is now partly transposed via Statutory Instrument, ref SI147 of 2011 (it doesn't appear to include transposition of Article 13, for example).

[3] "*Article 7 of the Renewables Directive now places the TSO under an obligation to examine other positive solutions that will guarantee dispatch and transmission of renewables, rather than simply seeking negative responses that reduce its output and efficiency. It should clearly have in place a first class forecasting system to enable optimal grid dispatch planning. As regards approaches to dealing with surplus energy at moments of low demand, there is energy storage, alternative uses of energy (use of heat pumps and CHP heat substitution) and energy exports, as has been done in other jurisdictions. ...*

The Renewables Directive, once fully understood, will be seen to place renewable energies ahead of all other energy sources in the dispatch merit order, since they get priority dispatch and may only be dispatched off for specific technical reasons, and also must have their output transmitted, except for reliability and safety reasons[3]. These guarantees do not apply to other forms of generation."

Page 6/7, Submission by Meitheal na Gaoithe to CER in response to ESBNG proposal on the conditions relating to the resumption of connection offers, 23 April 2004.

taken adequate measures to guarantee the transmission of electricity from renewable sources, and indeed has done little more than plan grid development and produce studies which show why renewable electricity can't be transmitted[4].

Support and project financing

Given that the EU energy market is still rather fragmented, and distorted by subsidies to fossil and nuclear and the non-internalization of their external costs, renewables are given direct and indirect supports to enable their rapid deployment. The most successful approach to support has been the guaranteed price scheme, championed by Germany.

Having tried tendering (the Alternative Energy Requirement, or AER), Ireland more recently adopted a scheme similar to Germany's, the Renewable Energy Feed in Tariff (REFIT). It operates on the same basic principle, by providing a regulated price for all generator output. Thus a bank could foresee a regulated income stream for a 15-year period, based on a highly reliable wind estimate (with 90% certainty in Ireland) and a known price, which is usually further de-risked here by being inflation proofed. That 'known' income stream would enable the bank to provide non-recourse project financing at a high gearing level (up to 80% debt, sometimes 85- 90%, until recently anyway). Promoters thus only need to find and get a return on 20% of the cost of these projects. Unlike fossil plant, a key feature of renewables, especially wind, that makes financing more difficult, is the high capital and low operating cost profile.

Regulatory interventions undermining projects

Given the adoption of a Government REFIT scheme, regulatory interventions that undermine this model (and project financing) include:

- making projects pay for grid which must then be transferred for free to the publicly owned network, including part payment for these in advance of bank financing (the controversial grid deposits);
- increasing 'standard' charges for grid items projects may not build themselves ('non-contestable');
- increasingly onerous grid code rules, which increase turbine specifications, connection requirements, and raise capital costs;
- substantial delays in grid delivery with limited consequences;
- market rules which introduce unpredictable project revenue volatility - TLAF/DLAF and TuOS charges;
- market rules which deny market revenue - inclusion of market capacity payments in REFIT floor price;
- absence of ancillary payments despite provision of ancillary services in compliance with grid code rules (reserve when curtailed, voltage support, reactive power provision);
- most serious of all is constraint or curtailment, reducing generator output, causing a loss of REFIT support, and usually market payments as well (projects with 'firm access' do get the market payment when constrained).

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[4] for example the EirGrid study, euphemistically entitled "Facilitation Of Renewables", June 2010

Of these, only grid code and constraint and curtailment, could be argued to be required to some degree to maintain grid stability, and thus could fall within the exemptions provided in the Renewables Directives. The wind industry does not wish to see grid instability, especially caused by wind. However that does not eliminate the obligation to take measures that avoid constraint and curtailment, a point to be considered further below.

Dealing with uncertainty

In the main, some judgement can be made about all of these issues in advance of project build decisions, though some like Transmission Loss Adjustment Factors (TLAFs), which are supposed to incentivize project location decisions, nevertheless proceed to vary unpredictably and indefinitely, after project construction (though this is currently under review).

In the case of constraint and curtailment, each project has to date been provided with a 'constraint report' with its grid connection offer, to assist decision-making. However, the reports that have been made available by EirGrid thus far for Gate 3 are provisional upon the outcome of the decision that the SEM Committee is now expected to make, and which is the primary subject matter of this paper. These reports are described as Possible Generator Output Reduction or PGOR reports, and are due to be confirmed or altered depending on the outcome of the SEM Committee's imminent decision (revision would take 6 months to one year).

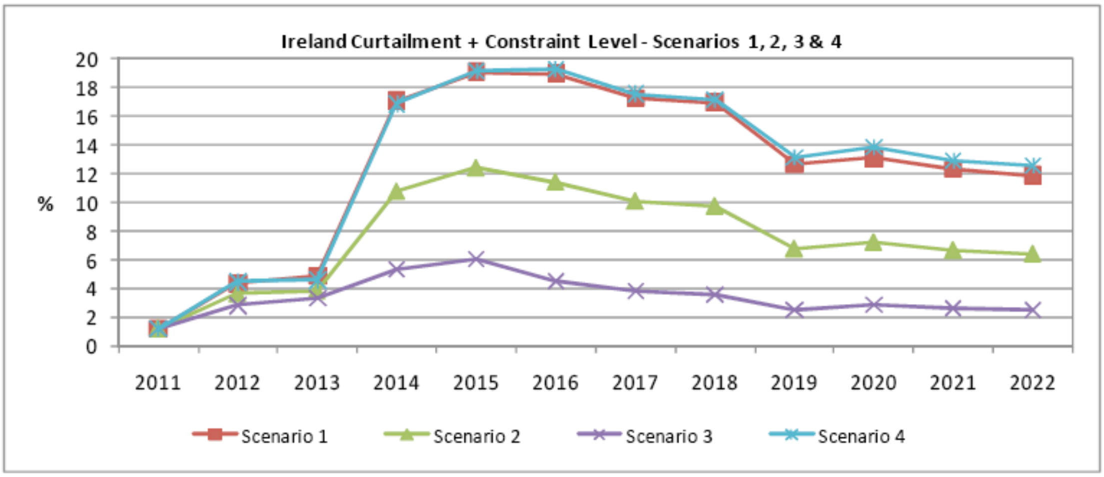

Figure 2.3: Ireland Wind Generation Curtailment and Constraint levels for Scenarios 1 - 4

The above diagram is an extract from the Area B PGOR, which shows up to 20% loss of output, which no project could sustain in the absence of compensation. The degree of non-firm constraint and most recently curtailment indicated in these PGOR reports is non-binding, and no compensation is being offered for any excess. Thus they are purely indicative, and projects need to take a view on the risks involved.

Project promoters also need to be aware of several risks, even with these potential fatal losses, which might imply even higher levels:

1. As illustrated in the diagram above, the modelled level of curtailment varies with the take-up of connections in Gate 3 (scenarios 1 to 4), and is thus affected

by their own decision, and that of hundreds of others, which makes the judgement almost impossible;

2. EirGrid appears to be assuming some exports and storage when modelling for these reports, and yet as we learned from another part of EirGrid, no exports are expected at all, and currently there is no active storage plant on the system;

3. Projects built on the basis of previous constraint reports have of necessity taken the view that it is reasonable to expect that new levels of constraint and curtailment, due to the arrival of subsequent projects, would not be imposed on them, retrospectively as it were; this is referred to here as 'grandfathering'. Assuming the SEM decision deviates from its current proposal, and reflects this principle, then the losses will be much higher for Gate 3 and later projects.

Current proposals

However, the System Operator has been arguing that this 'grandfathering' approach is technically difficult to implement, so that the proposal on the table is to pro-rata both constraints and curtailment across all projects, regardless of status.

So, where a transmission constraint affects several projects, all would be reduced equally, so that the newer projects have less constraint than they would have if the constraint level indicated for the older projects were respected. However those with firm access would receive market payments (but not REFIT).

In addition, projects already financed and built would be hit with curtailment they didn't allow for, thus undermining the banking of those projects, and introducing new uncertainties into the sector. The newer projects might appear to have less curtailment, at this stage, but of course as more projects come on behind them, and curtailment rises, they would also be hit with new unanticipated levels, undermining their banking as well.

The current regulatory view on curtailment is that it cannot be compensated, as that would be to pay for energy that is not only not generated, but is supposedly unnecessary as well. Indeed, it is believed that compensation would attract unending and apparently unnecessary renewable development (ignoring exports), with the cost spiralling out of control, another point to be considered further below.

In any case, where there is no compensation, there is little doubt that 'grandfathering' is the only workable policy. It is inevitable that output reductions will grow over time, so no project could be built under a simple pro-rata model, and this has been emphasised to the Regulators. Nevertheless the current proposal from the SEM Committee seeks to roughly pro-rata constraint and curtailment, insofar as possible. Early projects don't have the facility to be curtailed, and in reality optimizing curtailment has led to varying levels around the country, which then contradicts its definition as a system wide phenomenon, different from constraint.

Reasons for curtailment

There are a series of reasons for reducing the output of renewable generators to maintain current system stability:

1. renewable generation exceeds total system demand, and there is no export market;

2. renewable generation cannot be relied upon to meet rapidly rising demand (for example in the morning);

3. renewable generation provides limited 'inertia', as do today's DC interconnectors, while heavy rotating generators do, and the system needs inertia to cope with disturbances, requiring that there be a limit of the proportion of demand that can be fulfilled by variable generation (ie: wind).

4. certain system aspects are less than optimal, requiring that there be a stricter limit of the proportion of demand that can be fulfilled by variable generation (ie: wind) - discussed below.

However, since the problem of curtailment has been flagged for many years, by both EirGrid and the industry, sufficient time has elapsed for the authorities to take adequate measures to guarantee RES-E transmission, as required by the Directives, so as to avoid curtailment. Grid stability in the short term has been used as a blanket excuse to avoid taking measures which would make sure the system remained stable as more renewables came online, which is a perversion of the meaning and intent of the Directives.

As can be seen from the quote at footnote 1 above, it has been argued that those measures should have included storage and interconnection. However the former is ruled as being uneconomic, which is not a justified exclusion from taking measures under the Directive. The latter has been undertaken, modestly, but has not been set up in such a way as to provide a useful measure to address the issue, due to lack of inertia and absence of market rules. These are therefore excuses, not real reasons.

Specifically, the various excuses for curtailment listed above could have been addressed with appropriate measures:

Reason 1: active demand management, storage, interconnection;

Reason 2: active demand management, storage;

Reason 3: storage, AC interconnection, dispatchable renewables;

Reason 4: ROCOF adjustment, conventional grid code compliance, wind turbine performance, smart grid.

To explain the 4th point, here is an extract from a Gate 3 PGOR report:

"B.7.1 Limits on the Instantaneous Wind Penetration
To ensure adequate frequency performance and dynamic stability, the sum of the All-Island instantaneous wind generation plus imports is limited to a percentage of the total All-Island generation (i.e. demand plus exports). Figure B.4 shows the limits on the instantaneous wind penetration assumed for the study period covered in the constraints modelling. As can be seen, a limit of 50% is assumed for 2010 rising to 75% in 2019. The limit of 75% is maintained for all study years post-2019.

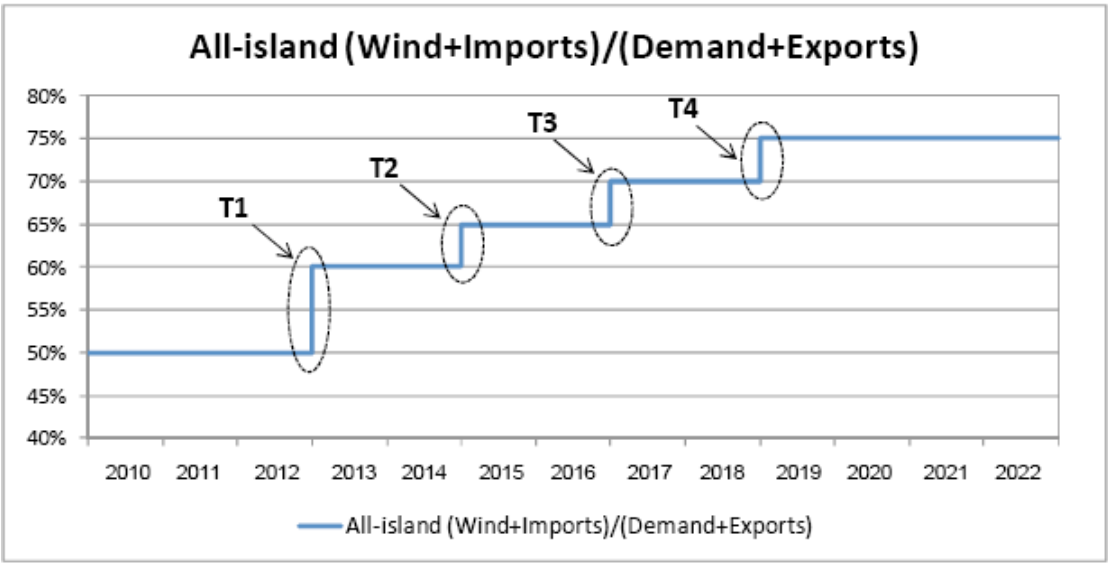

Figure B.4: Limits on the instantaneous wind penetration employed for the constraints modelling.

As can be seen in Figure B.4, a number of transitions in the instantaneous wind penetration limit, T1 – T4, are assumed to occur in the period between 2010 and 2020. However, in order for these transitions to proceed, certain preconditions must be satisfied:

· T1 (from 2013): The transition from a 50% to a 60% instantaneous wind penetration limit at the beginning of 2013 is dependent on the assumption that the impact of the DSO's Rate of Change of Frequency (ROCOF) relays on system performance will be resolved.

· T2 (from 2015): The transition from a 60% to a 65% instantaneous wind penetration limit at the beginning of 2015 is dependent on the assumption that the conventional generation portfolio can demonstrate proven performance with regard to flexibility of operation and ability to provide reserve in a grid code compliant manner.

· T3 (from 2017): The transition from a 65% to a 70% instantaneous wind penetration limit at the beginning of 2017 is dependent on the assumption that controllability, advanced frequency response, reactive power and fault ridethrough capabilities.

· T4 (from 2019): The transition from a 70% to a 75% instantaneous wind penetration limit at the beginning of 2019 is dependent on Smart Grid developments and installation of fast-acting network support devices such as Synchronous Condensers, Static Var Compensators and advanced Generator Controllers."

The apparent absence of these measures means that wind is limited to 50% of instantaneous demand rather than 75% (and as mentioned above, wind has already been curtailed as a result). It is notable that of the 25% difference, 20% is accounted for by measures which the system needs to adopt, but has failed to, while 5% is associated with wind turbines. However, all new turbines since around 2004/5 have been made to rigorously comply with the type of conditions mentioned under heading T3.

Proposal for output reduction

In the SEM, where a project is in the Market Schedule (which is prepared 24 hours in advance), but it is not run for whatever reason, it gets compensated (with the market price less its bid). If REFIT supported projects are affected, since they are treated as bidding zero, they get the market price, but where that is less than the REFIT price, they lose out on the difference (REFIT is currently paid on output generated only).

Given that plant other than renewables must apparently run all the time to provide system services, priority of dispatch should dictate that all renewables would be in the Market Schedule ahead of such plant. Putting them all into the Schedule could not, per se, compromise the stability of the system, since it is only a proposed dispatch. If the system demand is then less than total generation, some renewables would be curtailed, (eg: applying the 50-75% rule mentioned above, to protect stability), but they would be compensated.

However, the proposal on the table involves anticipating demand, and removing renewables from the Market Schedule in advance, to enable supply and demand to better match. This would also involve applying the 50-75% rule, in order to protect stability, so that up to 50% of generation in the Schedule, as well as the actual dispatch, would be non-renewable. Renewables whose output is reduced in by exclusion from the Market Schedule would receive no compensation.

The result as regards stability is exactly the same in both cases, so this is not the reason for this approach. Instead, the latter is simply a scheme for circumventing priority of dispatch and the transmission guarantee and avoiding payment to renewables for lost output.

As result of sustained pressure on this issue, the SEM Committee is proposing a 'material harm' test before implementing this approach. It is understood that a decision will follow in about two years. In other words, projects getting underway now, without this approach, may be subject to it at some point in the future. This makes absolutely no difference. The threat of the introduction of such an approach is enough to undermine the potential revenue stream of these projects, and make banking them more difficult or impossible. The only way it might work over the next two years is if it would only apply to projects applying for connection after 'material harm' was demonstrated.

All in all, this has been a very clumsy and damaging process, which has eaten away at the foundations of the whole renewable sector. Is it any wonder that the build rate was halved in 2010 to a mere 115 MW.

Clearly, the aim of the Regulators is to find a way to avoid paying renewable generators for the output they have lost due to the fact that the system has not been developed to take that output. Indeed, it has been clearly stated to us by the CER that the market shouldn't go on paying for such output, from an ever-increasing amount of renewable generation, as there must be a limit, and this is one way of setting that limit.

Limiting renewable development

However, who or what should ultimately decide how much renewables come on the system? Surely that is either a matter for the Government through its REFIT scheme, or for the market (home or export). Instead, we face a situation in which, first of all the authorities refuse to develop the system to take renewable power, then turn them off, then say they won't compensate them, and this limits our development. Thus the Regulator is either abrogating the authority of the State to itself, or contradicting that authority, or attempting to limit the market itself, which is not correct.

The role of the Regulator is to facilitate Government policy, and enable as much renewables as Government or the market decides. The Regulator may need to point out to the State what the cost of doing so is, so that the State can decide whether to do it or not, which is its correct role.

In truth, we suspect that the State is being somewhat inconsistent, by setting targets, making nice press statements, and then preventing the Regulator (whether actively or passively) from investing in the measures to enable our generation, not allowing him to pay renewable projects for output not generated, and thus limiting renewable development. Even if this approach is not actively directed by the State, it is ultimately the fault of the State, for not ensuring its authorities respect the Directives.

By way of example, at a recent discussion held with the responsible Department, DCENR, a request by the wind industry to be paid REFIT on the available output of the wind farms, rather than the metered output (which would solve the constraint and curtailment problem) was flatly refused. The reason was instructive - because the regulator wouldn't agree! So it appears that DCENR is allowing the CER to set national policy.

Grid access

Incidentally, the other important element of the grid rules in the RE Directives is access, whether priority or guaranteed. Fossil plant is connecting ahead of renewables, on security grounds, so we don't have priority access. Indeed, we had a moratorium on wind connections in 2003-4, during which a lot of fossil plant connected, and are still dealing with the consequences. The resulting delay in accessing grid has become so long now that planning can no longer be an access criterion. The result has been a grid connection bubble of the system's own making. Around 15,000MW of renewables is waiting to connect, 3,900 MW of which is in Gate 3. The rest certainly don't have guaranteed access. So the grid access clause of the Directive is also being broken.

CONCLUSION

Since 27th October 2003 (the transposition and direct effect date of the original RES-E Directive), the Renewable Directives have obliged the authorities to take measures to guarantee transmission of electricity from renewable energy sources, thus avoiding curtailment. This has been repeatedly pointed out to the authorities since that date. As illustrated above, it seems that the requisite measures could have been taken, albeit at some cost (which is not an exclusion permitted by the terms of the Directive). Instead the authorities have hidden behind their interpretation of the Directive, stating that the stability qualification meant that they didn't have to do anything, an interpretation that is incorrect and would, if accepted, render the grid rules of the Directives meaningless.

The result is that renewables now face the very real possibility of open-ended curtailment without compensation, and consequently an end to project finance for renewable projects, leading the industry to grind to a halt, despite the rhetoric and what are now binding targets. While the advent of non-compensation has been delayed, it nevertheless remains a real possibility for all projects, hanging like a Sword of Damocles over the whole future of the sector.

Since the authorities have not taken the requisite measures to guarantee the transmission of RES-E that they were obliged to, the industry could seek redress through the courts, though that won't be necessary if they are fully compensated (to the full value of the REFIT).

The 'PGOR' document quoted above provides clear evidence of the problem faced by the renewable sector in Ireland. Renewables are to have their output reduced to comply with a 50% cap, for stability reasons, because certain network measures still haven't been taken. However, as can be seen, these measures are scheduled to be taken over the coming years. This means that they do not compromise the stability of the grid, otherwise they couldn't be done. This is the start of the correct interpretation of the Directive. However, these measures could and should have been taken already years ago, as they do not (and did not) fall under the stability qualification in the RE Directive.

If the authorities could and should have done these things years ago, why are we to be made to pay for the consequences with lost output to an unknown extent, lack of compensation, and the effective closure of our industry? There is time for the authorities to make these and other key changes in the next 5 years, so as to avoid the worst constraint and curtailment that will otherwise arise in the second half of this decade.

The Regulators are proposing rules that would have the effect of stopping the development of the Renewables sector at some point, despite the grid obligations and targets under the RE Directives. They are thus being allowed to contradict their own Government policy, and we have to ask whether this is sanctioned or not. Either way is unacceptable.

It is of critical importance that the imminent SEM Committee decision retracts the threat of uncompensated open-ended curtailment and eliminates it completely from the discussions from now on. Given the failure to date of the Regulators to take adequate measures to secure the output of renewable energy projects, they ought to both accelerate that process immediately to minimize curtailment, as required by the Directive and compensate fully for any loss that cannot be prevented.

Furthermore, by indefinitely delaying access to the grid, the Regulators have breached the access rules of the Renewable Directives, and continue to do so.