Industry Insight

June 2015

A Closer Examination of Wind Generation in Ireland

How the changing market is making it hard for generators to forecast revenues

With enviable wind resources, ambitious renewables targets and generous support schemes, onshore wind generation in Ireland offers investors the potential to make healthy and stable returns at a time when yield continues to be elusive. However, the level of regulatory uncertainty currently facing the wind industry across Ireland, with several structural market changes occurring at the same time, has created a number of challenges for both current participants and potential investors in the Single Electricity Market (SEM).

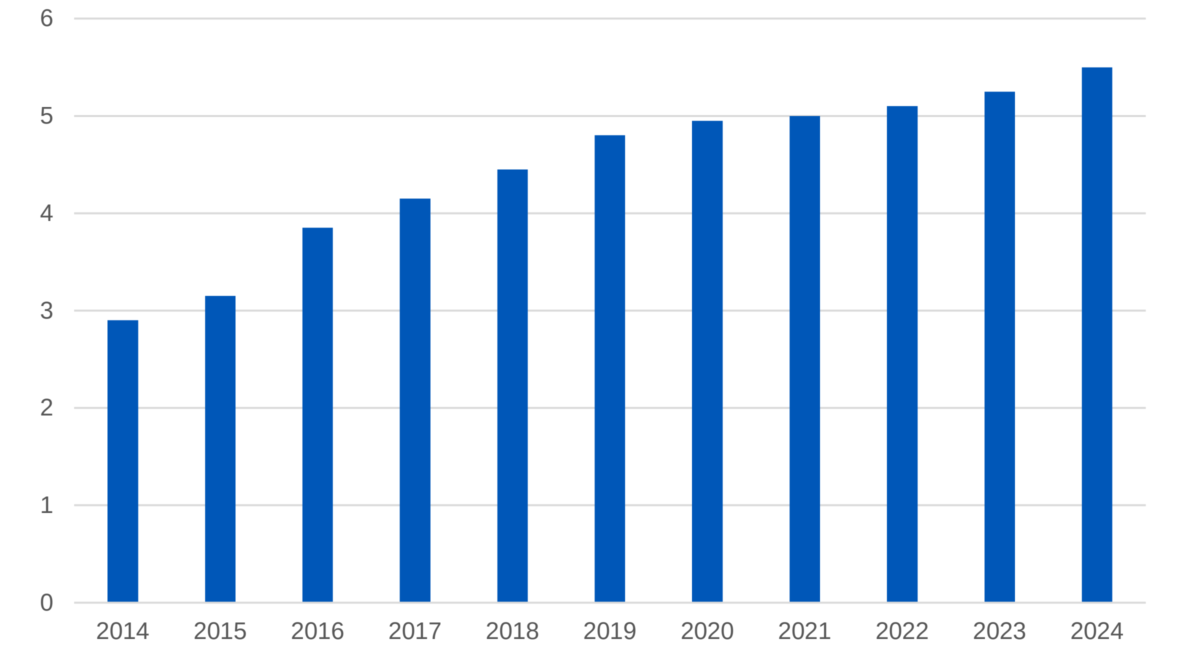
This updated follow-up to IPA's March briefing paper, which identified the issues that could have significant impact on future wind generation revenues, explores further how the changes currently taking place across the SEM might affect payments to wind generators.

Wind Generation in the SEM

Ireland's significant wind resources, as well as onshore wind generation's status as the most economic renewable technology, means that wind power is expected to be the driving force behind meeting the target that 40% of electricity should be generated by renewables across the Island by 2020.

Under a number of past and present support schemes, wind capacity within the SEM has grown from 182MW in 2002 to around 2,658MW at the end of 2014 – making up approximately 16% of total generation in 2014. In order to meet the 40% target, EirGrid and SONI estimate that wind capacity will have to almost double to between 4,300MW and 4,900MW by 2020, depending on future demand for electricity. Forecast wind capacity is shown in Figure 1 below. As of October 2014, there was around 5,000MW of planned or consented wind projects across the Island.

Figure 1: Forecast Wind Capacity (GW)



Source: All-Island Generation Capacity Statement 2015-2024

Bringing the required capacity online is going to require a huge amount of investment that both governments have so far looked to incentivise through generous renewable support schemes. However, the level of regulatory uncertainty facing the Irish wind industry, due to the energy, capacity and system services markets all being reformed simultaneously, has created a number of challenges for both current participants and potential new investors, most notably affecting their ability to accurately forecast future asset revenues.

Currently, in the Republic of Ireland, wind generator revenues are made up of the following components:

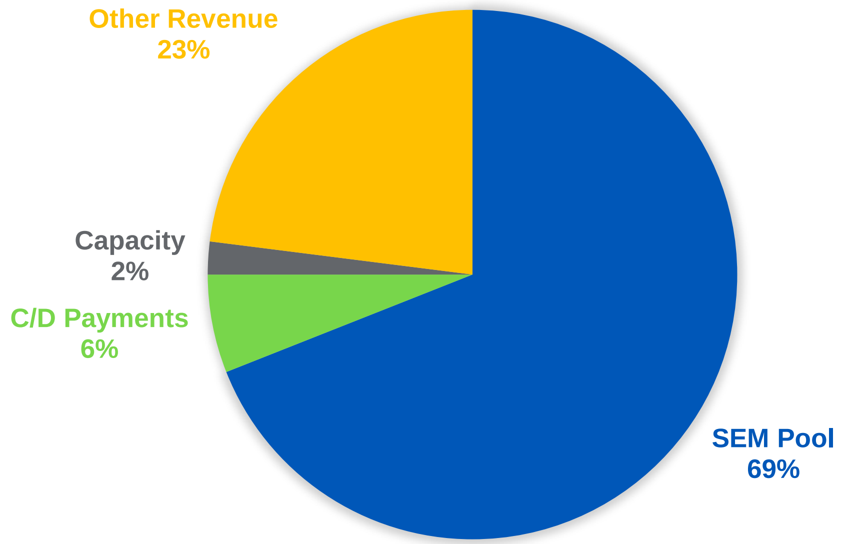
Wind Generator Revenue =

Market payment (Energy + Capacity + Constraint payments)

+ REFIT top-up

Figure 2 below shows a breakdown of the average revenues of wind generators in the SEM in 2013.

Figure 2: Wind Generators' Revenue by Source (2013)



Source: Adapted from Generator Financial Performance in the SEM (December 2014)

In 2013, around 69% of the revenue for an average wind generator came from the energy market, while only 2% came from capacity payments. Revenue from Contract/Difference (C/D) Payments (which includes Contracts for Differences, Renewable Energy Feed-in Tariff (REFIT) payments and Renewable Obligation Certificate payments) were also small at 6%, possibly because the 65.71 EUR/MWh average System Marginal Price (SMP) price for the year was not far below the 2013 REFIT Reference Prices for large (69.2 EUR/MWh) and small (71.7 EUR/MWh) wind generators.

This paper explores in greater detail how the move to the Integrated SEM (I-SEM), as well as other changes currently taking place within the market, might affect payments to wind generators:

- **The new REFIT Market Reference Price**

  Currently the REFIT top-up is determined relative to the ex-post SMP from the SEM Pool. Under the new Energy Trading Arrangements (ETAs), due to start in 2017, generators will be able to sell their power in a range of different markets. As a result, the Commission for Energy Regulation (CER) will have to decide on a new Market Reference Price. Its aim is to make that price as representative of the “actual” price that wind generators are receiving. Depending on how individual wind generators then trade, the top-up they receive could be less than what they need in order to achieve their REFIT Reference Price.

- **The new trading arrangements and imbalance**

  Under the new ETAs, all parties will have responsibility for self-balancing. This means that generators will be penalised when their outturn generation differs from their contracted position. Since wind generators will be required to take a market position based on a forecast of how strong the wind will be, they will be exposed to imbalance prices whenever their forecast is inaccurate. Whether or not any imbalance charges can be offset against REFIT reference prices is unclear, although improved alignment with the GB market’s trading arrangements should help wind generators trade efficiently on the interconnectors to balance their positions intra-day.

- **The new capacity market**

  Under the new ETAs, the current capacity payment to generators will be replaced by Centralised Reliability Options (ROs). This will be a quantity-based Capacity Remuneration Mechanism (CRM) under which generators will receive regular payments in exchange for paying back the difference between a predetermined “strike price” and the SMP whenever the SMP is above the strike price. However, for wind generators, there is far greater uncertainty as to whether they will actually be available to generate since price spikes are most likely to occur because wind is not generating. This suggests that wind would be penalised more than any other technology class, forcing generators to factor this implicit penalty into their Reliability Option offer, potentially making them uncompetitive. The loss of capacity payments represents a risk to revenues above REFIT floor levels and to generators in their post-REFIT periods.

- **Curtailment and constraints**

  Wind generators benefit from priority dispatch, but can have their output reduced for system security reasons or because of local transmission constraints. While Firm generators are currently compensated for any curtailment, this will change after 2017. This means that delays to DS3, the work programme to increase the possible contribution of wind in any period, will lead to higher levels of uncompensated curtailment for wind generators.

The REFIT Renewable Support Scheme

How does the current support scheme work?

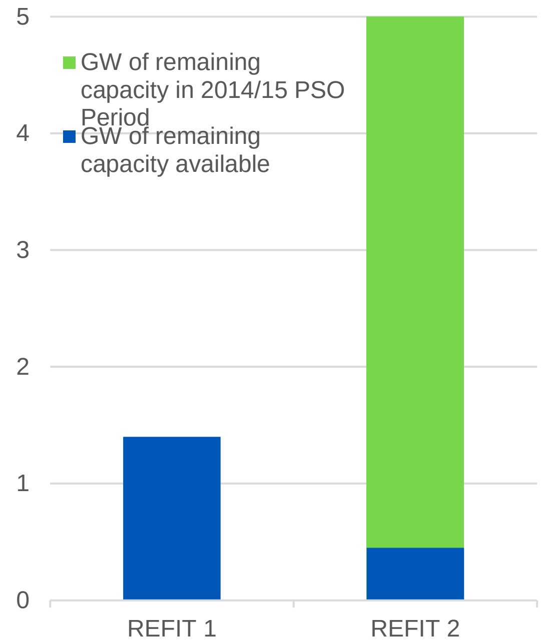
REFIT is a 15 year support scheme that is paid to supply companies that sign a qualifying Power Purchase Agreement (PPA) with a renewable generation project. Under the scheme, suppliers sell renewable power into the SEM Pool and pay the generator a technology specific reference price defined by the REFIT terms and conditions and agreed in the REFIT PPA. If the market price is less than the REFIT Reference Price plus an additional payment known as the “balancing payment”, the supplier is topped up from the Public Service Obligation (PSO) levy fund.

The balancing payment, which is designed to cover the costs of “balancing” variable wind generation in the energy market, is a legacy from the pre-SEM market arrangements where suppliers were compensated for incurring penalising imbalance prices called “top-up” and “spill”[1]. With the introduction of the SEM in November 2007, where there are no direct imbalance penalties associated with wind generation, the “balancing payment” has become the equivalent of a guaranteed margin for the supplier.

There have been three REFIT schemes to date: REFIT 1 was introduced in 2007 but is now closed, while REFIT 2 and REFIT 3 were both introduced in 2012. REFIT 1 and REFIT 2 were available to wind generators. Figure 3 below shows a breakdown of the renewable capacity supported under REFIT 1 and REFIT 2 schemes in 2014/15, as well as the remaining capacity available under REFIT 2. Almost all capacity supported under these two schemes is onshore wind.

[1] Doherty, Ronan; O'Malley, Mark (2011) “*The efficiency of Ireland’s Renewable Energy Feed-In Tariff (REFIT) for wind generation*”

Figure 3: REFIT Supported Renewable Capacity (GW)



Source: CER PSO Levy 14/15 Proposed Decision Paper – CER/14/125

The reference prices under both the REFIT 1 and REFIT 2 schemes for small (<5MW) and large (>5MW) wind in 2015 are 72.17 EUR/MWh and 69.72 EUR/MWh respectively. The REFIT 1 balancing payment in 2015 is 10.458 EUR/MWh, equivalent to 15% of the REFIT 1 Reference Price, while the REFIT 2 balancing payment remains fixed at 9.90 EUR/MWh.

How will REFIT change with the move to the I-SEM?

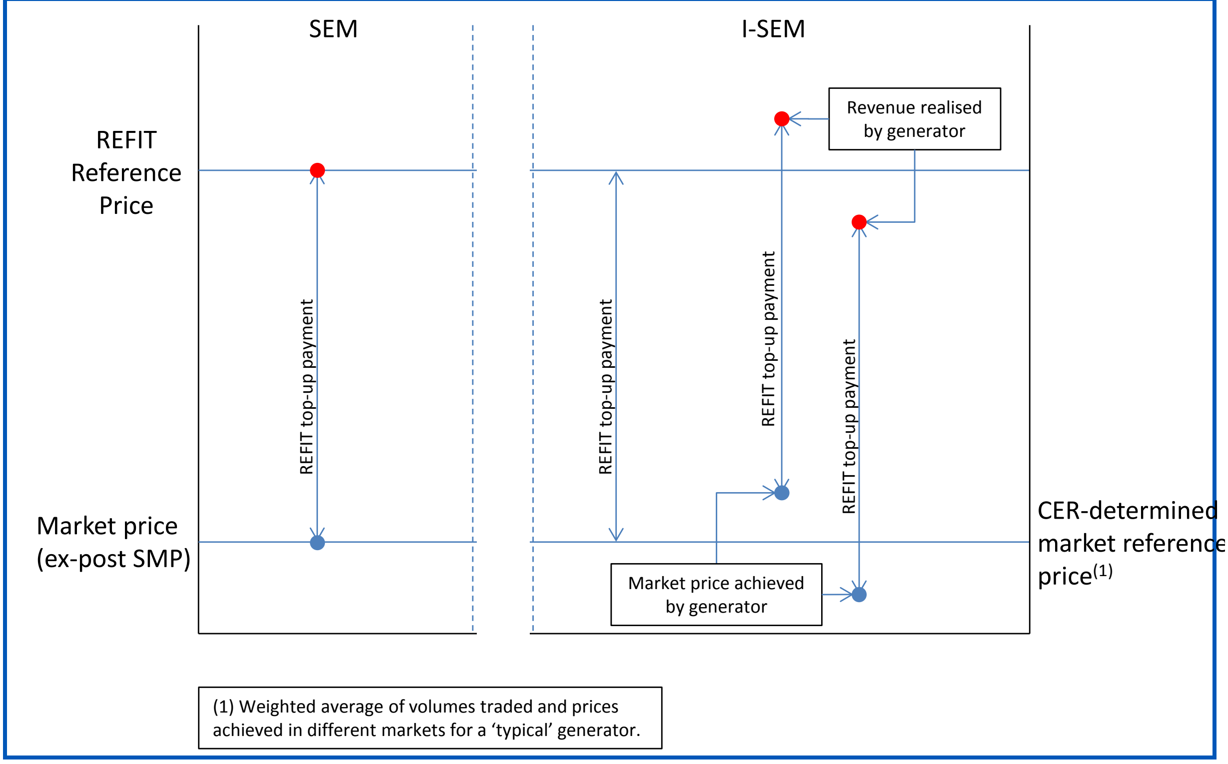
At the moment this is unclear as the detailed implementation rules for I-SEM are still being worked out. Currently, under SEM, the size of the top-up to the REFIT Reference Price is determined by the ex-post SMP from the SEM Pool. This price is "robust" since all generators have sold their power through the SEM Pool.

Under the new ETAs, generators will be able to sell their power in a range of different markets – e.g. forward, day-ahead, intra-day – making the concept of a single market price redundant. CER will therefore have to decide whether the new Market Reference Price to be used is based on a single market or weighting across more than one market. CER's aim will be to make this price as representative as possible of the "actual" price that wind generators are receiving.

Depending on how individual wind generators then trade, the top-up (i.e. the difference between the CER-determined Market Reference Price and the REFIT Reference Price) might not be sufficient for them to achieve their specific REFIT Reference Price. The details will be decided in the design stage but the compromise will, as always, be between avoiding a significant increase in the PSO levy on consumers, which is around EUR 330 million for 2014/15, and maintaining the certainty and stability that the REFIT scheme has brought to investors in wind generation. It appears critical to both existing projects and the development of new capacity to meet the Island's 2020 targets that certainty in relation to REFIT continues.

The differences between generators' realised prices in the SEM and I-SEM is shown in Figure 4 below:

Figure 4: Generators' Realised Prices: SEM versus I-SEM



The Trading Arrangements and Imbalance

How is imbalance currently treated in the SEM?

In the SEM, wind generators do not submit independent forecasts of their generation to the system operator, but rather the system operator forecasts their dispatch and then schedules other units in line with that forecast. Actual availability values are used to calculate ex-post prices, meaning there is no issue with the accuracy of the availability profiles of wind generators and, therefore, no way for them to be in imbalance.

Uninstructed Imbalance

In the SEM, thermal generators can be in "uninstructed imbalance" if their actual generation varies from the dispatch level instructed by the system operator. Beyond a certainMW "tolerance band", a thermal generator is penalised by having to either buy back any power it failed to generate at a predefined mark-up to the SMP or sell any extra power it over generated at a discount to the SMP. Since the penalty is not market driven, it does not expose generators to unexpected high prices.

How will that change under the I-SEM?

Given the existence of ex-ante physical trading, the I-SEM will require a method of settling generator imbalances. A party's imbalance will be the difference between their contracted position at gate closure, adjusted for any subsequent trades in the balancing market (BM), and their metered generation (or demand if they are load). All market participants will be balance responsible, meaning that any physical imbalance volumes are settled at the single marginal ex-post price for each settlement period reflecting the marginal costs of energy balancing actions taken by the system operator. This means that a generator that over generates (or load that under demands) will receive the same imbalance price for their spill as a generator that under generates (or load that over demands) has to pay to "buy back" their shortfall in each settlement period.

How will the change affect wind generators?

Since differences between forecast and actual wind generation can be significant, wind generators are likely to be more exposed to imbalance prices than controllable thermal units. The key to reducing their exposure will be for wind generators to be as accurate with their forecasts as possible, something that is clearly easier for large players with sophisticated modelling capabilities than for small generators. A possible solution would be for system operator forecasts to be available to generators to trade against.

The High Level Design (HLD) decision states that "some" small renewable generators will be able to balance on a portfolio, rather than individual unit, basis but exactly what this means will not become clear until the detailed design stage is complete.

Understanding how renewable generator imbalance is treated under REFIT will be one of the most important elements in understanding an individual generator's potential exposure. As explained above, the "market" payment, to which the REFIT top-up is applied, is the sum of energy, capacity and constraint payments. If imbalance payments/charges are included in this definition of revenue, imbalance exposure would only affect revenues above the REFIT floor.

The Capacity Mechanism

How is capacity remunerated under the current SEM?

Ireland currently has a form of price-based Capacity Mechanism under which generators receive payments to cover their fixed costs. This is necessary to ensure generation adequacy because SEM rules mandate generators to bid into the SEM Pool at their Short-Run Marginal Cost i.e. just their cost of generation (fuel, CO2 and variable operating costs).

Under this mechanism, an annual capacity pot is calculated based on the annualised fixed costs of the most efficient peaking plant, multiplied by a capacity requirement based on a specified reliability standard. This pot is then distributed across all hours in the year, weighted by demand in those hours, and paid out to all generators according to their availability in that period[2] .

How will the capacity payments change?

Due to the lack of a market mechanism, capacity payments are not seen as being consistent with the underlying principles of the EU Target Model and have therefore been reviewed as part of the move to the I-SEM. The SEM Committee decided in September 2014 that the new mechanism will be based on ROs.

Under this approach, a central agency, most probably the system operator, determines how much capacity is required to ensure system security. It then seeks to purchase ROs for that volume of capacity from generators and demand-side response through a competitive auction. An RO is a financial one-way contract-for-difference (CfD) that is linked to a Market Reference Price (for example, the price in the Day-ahead Market). If the Market Reference Price

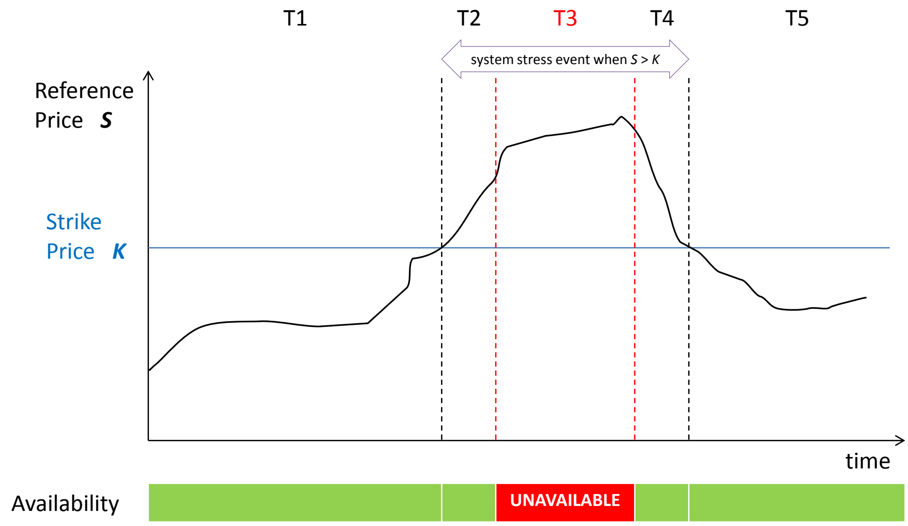
[2] The pot, known as the Annual Capacity Payment Sum (ACPS), is calculated each year by the Regulatory Authorities by multiplying the capacity requirement by the annual cost of the most efficient peaking plant, or Best New Entrant (BNE). This ACPS is then allocated across each month, weighted by peak to trough demand. Capacity payments will therefore be different in each half-hour period. Each available MW in that half-hour period will share in that half hourly pot. For 2015, the annualised fixed cost of the BNE is 81.60 EUR/kW/year and the Capacity Requirement is 7,046MW. This gives an ACPS for 2015 of around EUR 575 million.

increases above the Strike Price of the RO, the holder of the RO must pay the difference to the buyer of the RO. In return, the RO holder receives a regular stream of payments.

If the holder fails to provide electricity or demand reduction at times of "system stress", they pay a penalty to the buyer. The penalty can be split into two parts: the CfD aspect and an explicit penalty aspect. The CfD aspect is equal to the difference between the Market Reference Price and the Strike Price for each unit of capacity contracted under the RO. This means that the size of the penalty increases with the severity of the stress event. The explicit aspect of the penalty is set administratively to reflect the lower value to the system of less reliable plants.

Figure 5 below shows the payments made to a generator with and without ROs for a certain spot price, as well as the corresponding price paid by demand.

Figure 5: Example of Reliability Options



Payments to Generator

	T1	T2	T3	T4	T5
With RO	*S*	*K*	– (*S* – *K*) – ***P****	*K*	*S*
Without RO	*S*	*S*	*0*	*S*	*S*

**P* – Administratively set penalty*

Source: Adapted from Prof. Ignacio J. Pérez-Arriaga (2010) Long-term guarantee of supply in generation

What will the new mechanism mean for wind generators?

The new mechanism has not been welcomed by the Irish wind industry, which has suggested that ROs discriminate against variable generation[3].

Under the RO mechanism, holders of ROs will have to be online and generating during "system stress" events, defined as being when the Market Reference Price exceeds the Strike Price of the RO. This has led some to argue that, particularly for wind generators, there is far greater uncertainty as to whether they will actually be available to generate during "stress" events, since price spikes will often be caused precisely because wind is not available. This suggests that wind would be penalised more than any other technology class, forcing generators to factor these penalties into their RO bid in the auction.

If these penalties made wind generators very uncompetitive, they could miss out on receiving capacity payments altogether. However, given that capacity payments only made up 2% of the revenues of an average wind generator in 2013 (see Figure 2), it would not seem that a large proportion of plant revenue is at risk. Moreover, rather than missing out on capacity

[3] SEM Committee: HLD Summary of Responses (SEM-14-085c)

payments altogether, it is more likely that wind generators will simply have to think extra carefully about how much of their installed capacity they consider to be “reliable” enough to bid into the auction.

If the move to ROs means that wind generators will lose some or all of the capacity payment, one could expect merchant wind producers (i.e. those outside of the REFIT support scheme) to be hit hardest since the capacity payment represents an additional revenue stream for them on top of energy payments from the SEM Pool.

For generators with REFIT PPAs, the impact will not be as great. Whereas the sum of the energy payment plus the capacity payment might previously have exceeded the technology-specific REFIT reference price, the energy price alone will now less frequently exceed that price. It should also be noted that the full capacity revenue will be lost by these generators in their post-PPA periods during which they will operate as merchant plants – this will have the biggest impact on REFIT 1 generators since they are the closest to the end of that period.

Curtailment and Constraint

What is curtailment and constraint?

The SEM operates on the principle of priority dispatch of renewable generation over fossil fuels. However, sometimes it is necessary for the system operator to reduce renewable output, normally wind, and dispatch thermal generators instead. This is known as “curtailment” and is necessary because the variable and non-synchronous nature of wind generation means that the transmission system and system services markets are currently only capable of supporting an instantaneous wind output of up to 50% of total demand. Any more wind than this would pose a risk to the system. Wind can also be “constrained down” to reduce local transmission bottlenecks. Table 1 below shows average dispatch-down levels across the All Island System between 2011 and 2013.

Table 1: EirGrid Estimated Breakdown of Historic All-Island Dispatch-Down

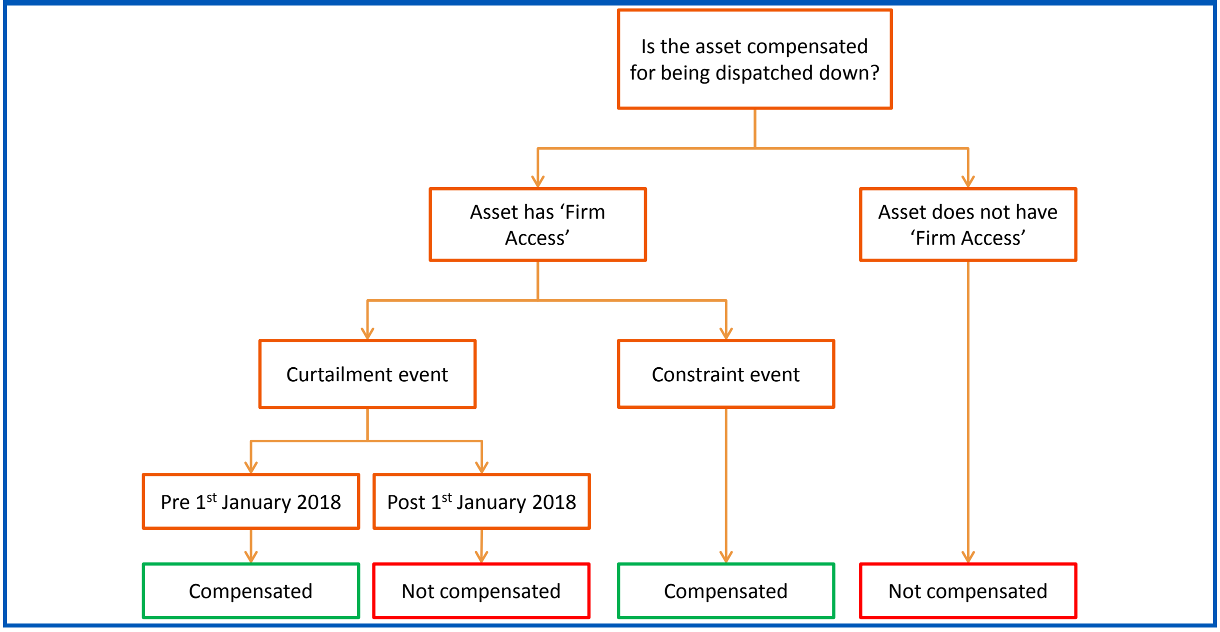
	2011	**2012**	**2013**
All Wind Dispatch-Down Vol (MWh)	105,741	110,291	195,534
All Wind Generation (MWh)	4,208,007	5,143,295	5,872,102
Dispatch-Down (%)	2.5%	2.1%	3.3%
...of which Curtailment (%)	2.0%	1.3%	2.4%
...of which Constraint (%)	0.5%	0.8%	0.9%

Source: EirGrid Annual Wind Constraint and Curtailment Reports 2011[4] , 2012[5] and 2013[6] .

Currently, generators are compensated for any Firm Access Quantity (FAQ) that is curtailed or constrained down, while those without FAQ are not compensated. However, according to SEM-13-010, neither firm nor non-firm capacity will receive compensation for curtailment after 31 December 2017. This approach to curtailment and constraint is summarised in Figure 6 below.

[4] http://www.eirgrid.com/media/2011_Curtailment_Report.pdf
[5] http://www.eirgrid.com/media/2012_Curtailment_Report.pdf
[6] http://www.eirgrid.com/media/Annual_Wind_Constraint_and_Curtailment_Report_2013.pdf

Figure 6: Compensation for Curtailment and Constraint



What are the Regulatory Authorities doing about this problem?

The DS3 (Delivering a Secure, Sustainable Electricity System) programme has been underway since 2011 and aims to increase the amount of wind that the grid can support. One of the main work streams of the programme is to reform the system services markets to incentivise the required "flexible" generation. As the improvements are made, the system non-synchronous penetration (SNSP) limit, the maximum amount of wind (and generation via interconnectors) as a percentage of demand at any point, will be increased, reducing the frequency and size of curtailment events. According to the latest DS3 Programme Operational Capability Outlook (April 2014[7]) the expected schedule for increases in the SNSP limit is:

- Q4 2016: 55%
- Q4 2017: 65%
- Q3 2018: 70%
- Q2 2019: 75%

What are the risks to wind generators?

The main risk to wind generators is the possibility of delays to the DS3 work streams, especially given that even those with FAQ will not be compensated for curtailment after 2017. While in theory it is possible that the 2018 deadline could be moved in the event of major delays to the increases in the SNSP limit, the Regulatory Authorities have not indicated that this will happen.

There have already been a number of delays to the programme that have prevented the SNSP limit being increased beyond 50%. Any further delays, especially if new wind capacity continues to come online, could significantly increase the level of curtailment for wind generators, costing them significant amounts of revenue.

[7] http://www.eirgrid.com/media/DS3_Programme_Operational_Capability_Outlook_2014.pdf

How can we help?

IPA Advisory is a leading independent advisory practice providing professional consultancy services in Markets & Transactions, Regulation & Policy and Public Private Partnerships across the Power, Oil, Gas and LNG, Water and Infrastructure sectors. Our specialist advice includes: policy development and evaluation; market and economic analysis using proprietary models; market design and reform; and capacity building and workshops.

For twenty five years IPA has been designing and developing bespoke market simulations for investors seeking to enter new markets and value investment opportunities in merchant, contracted and mixed markets. This has been complemented by regulatory risk analysis and mitigation strategy development.

We have a proven track record as market advisor for M&A, IPO, financing and refinancing activities in numerous jurisdictions, working for lenders as well as project sponsors. Since 2007, we have supported successful deals valued at some US$25 billion, involving over 32GW of power generating capacity globally.

What services have we recently provided?

IPA has helped a range of clients understand the Irish regulatory environment and how policy changes could affect the electricity generation market. We have closely followed the development of I-SEM programme and advised extensively on the ways in which the issues discussed within this paper can be understood and handled.

We have used our proprietary in-house power market model, ECLIPSE™, to provide forecasts of the system marginal price and capacity build-out, as well as captured prices, load factors, capacity payments and gross earnings for specific renewable portfolios. We have also modelled different DS3 delay and wind build-out scenarios to understand how different levels of curtailment could impact generator revenues.

Who have we worked with?

- Brookfield Renewable on its acquisition of the Bord Gáis onshore wind portfolio.
- The Regulatory Authorities on their economic appraisal of DS3 system services.
- CDPQ on its acquisition of a stake in the London Array offshore wind farm.
- Marubeni and the Green Investment Bank on their acquisition of a stake in the Westermost Rough offshore wind farm.
- A renewable energy company considering developing anaerobic digestion projects in Northern Ireland and Great Britain.

For further information please contact:

Jonathan Thurlwell, Managing Principal – Policy, Regulation & Infrastructure

T: +44 (0)20 7659 9866

E: jonathan.thurlwell@ipaadvisory.co.uk

IPA Advisory Limited
74 Wigmore Street, London W1U 2SQ, UK
www.ipaadvisory.co.uk

T: +44 (0) 20 7659 9888
F: +44 (0) 20 7935 3059
E: contact@ipaadvisory.co.uk