Renewable Energy Generation's Goonhilly wind farm in Cornwall, southwest England

Wind power is being relied on by governments around the world to deliver on their promises of low-carbon power. But who is left holding the financial risks inherent to this resource? And what are the prospects for a mature wind derivatives market developing to allow the transfer of risk? Ned Molloy reports

WHO SHOULD PAY?

Wind power is one of the fastest growing energy sources, with annual growth averaging 26% since 2005, and capacity growing over 1,000% in the last decade to 195 gigawatts (GW) in 2010 from 18GW in 2000, according to the International Energy Agency (IEA). But while renewable energy is crucial to helping countries hit their carbon emissions reduction targets, the increased used of wind is introducing a slew of risks that need to be managed.

Chief among these risks is intermittency. The question of whose responsibility it is to shoulder wind variability risk and its associated costs is becoming ever more pressing as wind power expands as a percentage of national generation portfolios. Power Purchase Agreements (PPAs) are becoming more sophisticated as both generators and buyers gain a better understanding of the risks involved. However, demand is growing for better ways of managing these risks through hedging and the use of derivatives.

The increased use of wind power also throws up larger issues of grid operability, scheduling, trading, infrastructure build and creating a fair system. Different countries have tackled these issues in very different ways, all with positive elements and drawbacks, but at present there is no framework that successfully addresses all the issues.

In 2010, renewable energy supplied an estimated 16% of the world's final energy consumption and nearly 20% of global electricity productionthis figure is expected to increase significantly over the next few decades, with wind power taking the biggest role.

To achieve the IEA's scenario of halving energy-related carbon dioxide emissions by 2050, global renewable energy generation must double from today's levels by 2020, as part of which, wind power must see an annual average growth rate of 17%. Given that its current annual growth rate is 26%, the sector looks well on track to reach the IEA's projection, and attain 575GW installed capacity by 2020.

Although China accounted for half of all new global wind capacity added last year, and now has the largest installed capacity of any single country at 44.7GW, Europe as a whole is still in the lead at 84GW installed capacity. According to the plans submitted by EU countries to the European Commission, 34% of total EU electricity demand will come from renewables by 2020, led by wind power at 14%.

In the US there is no national-level obligation, but nearly all of the states have legally binding Renewable Portfolio Standards (RPSs) in place, which require utilities to use renewables for a certain percentage of their retail electricity sales or a defined share of their generating capacity (or buy the equivalent renewable energy credits). California, a frontrunner, requires its electric utilities to derive 33% of their retail sales from eligible renewable energy resources from 2020 onwards. Renewable obligations also exist at the provincial level in Canada and India, and at the national level in Australia, Chile, China, Japan and the Philippines. Worldwide, at least 119 countries have some sort of renewables target or incentive scheme in place.

While incentive schemes for wind generation vary greatly around the world, there are key commercial questions that all wind farm developers and governments must ask: by how much do wind speeds vary at a certain site, on what time scale, with how much predictability?

While there is intra-hour, intra-day, and intra-month variability, a netting effect over longer timescales also

exists, so that if a wind farm has a bad Tuesday, maybe Wednesday will make up for it, if it has a bad June, maybe January will cancel it out. This netting effect over the long term provides enough predictability at least for wind power developers to gain access to capital. The major challenges around wind generation occur at the point of scheduling and trading, although underperformance of wind power from one year to the next can also be significant, say market experts.

"You can see hour-to-hour variability of capacity factors, going from 0% to 100% capacity in two hours. But in the grand scale of things, that's a problem for power trading and scheduling, not necessarily a problem for financing," says Michael Grundmeyer, vice-president of business development for North America and Europe at weather data company 3Tier, in Seattle.

However, longer-term there can also be 10% swings in average production year-on-year, with a large effect on cumulative megawatt hours (MWh) generated. "There was a one-in-50-year event in Q1 of 2010 in North America, when the Midwest, Northwest, and Ercot/Texas – all with thousands of megawatts installed capacity – were significantly underperforming," says Grundmeyer.

European wind power operators have also had to cope with underproduction. Scottish & Southern Energy (SSE) is the largest generator of electricity from renewable sources across the UK, and according to its half year results report in November 2010, it experienced a weather-related fall of 16% in the output of renewable energy from its hydroelectric schemes and wind farms, contributing to a reduction in adjusted profit before tax to £385.5 million for the six months to 30 September 2010, from £410.5 million in the six months to September 2009. According to an operational update from SSE from February this year, in the nine months to December 31, 2010 compared with the same nine months in 2009, output of wind energy was down by almost 20% on a like-for-like basis, excluding new wind farms built.

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This open exposure of profits to long-term wind variability is typical for generators of all categories, including independents, utilities and self-generators, according to Nicholas Perry, an independent energy consultant in the UK. "The usual 'risk management' technique, if you can call it that, is to work on the principle that things will even out over the long run. Most generators don't typically hedge against a bad year at all," he says.

But although financial hedging remains a minority pursuit among wind generators, there are other ways to manage wind speed risk. PPAs are the standard link between sellers and buyers of wind energy worldwide, and the negotiation of a PPA's terms are a battleground over who will bear the costs of wind speed risk. In the UK at least, sellers are winning this battle, according to Perry.

"Independent wind generators selling the output of a single wind farm or small cluster try to get the buyers of wind power to accept very one-sided contracts, whereby the buyer, often a large industrial or commercial user, has no rights to expect anything more precise by way of offtake assurances than just 'whatever gets generated' - thus putting the onus on them to make their own back-up arrangements, either by having physical back-up supplies (diesel etc), or just a balancing arrangement with a regular utility, which will be relatively expensive because of the unpredictable quantities involved," he says.

"The generator may suffer a hit on their own revenues if the wind doesn't blow – but they are trying to avoid at all costs the impact of the intermittency itself, namely exposure to the balancing mechanism, or the price of buying in replacement power at short notice – often a high price. This is the 'hidden cost' of wind, and they are very determined not to get saddled with it if they can," he adds.

David Crockford, group finance director at Renewable Energy Generation

Renewable Energy Generation

Wind generators, however, contest the characterisation of PPAs as one-sided. David Crockford, group finance director at Renewable Energy Generation (REG), a UK-based developer of wind assets, argues there is a level of *quid pro quo* involved. "There is no volume requirement in our PPA, so if I don't generate anything, I'm not penalised for that. So the buyer takes all of that risk onboard. However, in some respects as a seller of power I take a discount against market price in order to share that risk."

Increasingly though, off-takers of power are becoming more sophisticated and insisting that their PPAs should contain output guarantees or availability guarantees, or both. Output guarantees are standard in most PPAs in the US nowadays.

But even dealing with wind speed risk in this way, buyers are probably not getting the most efficient pricing, and they're not allocating volumetric risk to a party that can handle it, according to 3Tier's Grundmeyer. "If buyers manage to insert provisions into their PPA guaranteeing a certain number of megawatt hours or capacity factor, it seems like a concentration of risk on the developer side, especially if the developer is exposed to multiple projects in one region using the same guarantees. With a certain weather pattern they could get hit on their earnings in large chunks."

Conversely, if a PPA requires the buyer to purchase all of the seller's output, the buyer is exposed to the risk of having too much wind-sourced power on its hands at a time of high wind speeds and low power prices, which would mean losing money (unless the terms of the PPA allowed them to pass the losses back to the generators, which merely moves the risk somewhere else).

Concerns such as these have fuelled demand for ways to financially manage wind speed risk outside the framework of a PPA.

"There are quite a few wind farms that are financially supported by bank hedges, and those hedges take different forms," says JP Morgan's Christopher Calger, managing director, project finance, in New York. "JP Morgan has priced, structured and executed both financial-shaped swaps, as well as physical PPAs."

But although many deals to directly hedge wind speed risk have been implemented in Europe and the US over the last 10 to 15 years, the numbers are still small. "At the moment, the percentage of wind producers globally who hold wind speed derivative contracts is in the low double digits," says Marcel Stäheli, director, corporate solutions, at Swiss Reinsurance Company in Zurich.

Frustratingly for those involved, wind derivatives have often seemed to be on the point of becoming a mainstream energy risk management tool, before external factors make them uneconomical. An originator at a major European utility, who used to work at an investment bank, explains: "We always linked wind derivative deals to refinancings or financings of new wind farms. These deals were successfully executed with wind farm operators where the cost of the hedge was lower than the following reduction in financing costs. We did four or five in Europe between 2003 and 2005. And then in the mid-2000s, many Spanish banks came in and offered very favourable, very low financing conditions for wind farms. And after that the benefits of the wind hedges were not that obvious any more, because it was simply an additional cost," he says.

Nevertheless, a few companies are still innovating in the space. "We've completed a few deals out of Australia, and we're looking at deals in other parts of the world," says San Francisco-based Quentin Hills, global head of financial risk products at insurance firm Marsh. "Typically we reference it to wind speed at the site, and we can do that in the form of a collar, where a producer will give up the upside to protect the downside, or more of a swap type arrangement, when they just fix the wind speed so they get compensated when it falls below that and they give up above that at the same strike."

One factor holding back the take-up of wind derivatives in the past has been what data to settle them on. With many wind farms in remote locations, basis risk comes into play. What is the correlation between the actual wind speed at the site versus the speed measured at the nearest meteorological station? And if a multi-million pound wind speed hedge is to be settled off the data coming from an anemometer in the middle of nowhere, moral hazard and technology risk are big factors – the measuring device could be purposefully altered, or suffer mechanical faults which skew the annual data.

A new wind derivative contract launched earlier this year by Galileo aims to take all of these problems out of the equation, by settling the contract from objective third-party wind speed models provided by 3Tier, customisable to any point on earth. Many involved in the weather derivatives space are positive about its chances of success, but think the cost factor is all-important in determining whether it will truly take off.

A more fundamental question for wind derivatives is whether there is a natural market for them. When comparing wind to the established markets in oil, gas and power derivatives, the obvious question to ask is which parties would take the other side of the trade – in other words, who is naturally short wind. The answer could turn out to be thermal power plant operators.

"As the installed capacity of wind resources increases, certainly their availability will have an influence on power pricing itself. So the natural other side may just be the gas-fired generators," says Bill Windle, managing director of RenRe Energy Advisors in Houston.

But this will be a gradual transition,

Quentin Hills, global head of financial risk products, Marsh

cautions 3Tier's Grundmeyer. "We need to start this process with asset owners, and then look to the secondary market to find the folks that are interested in laying off their exposure to being interrupted by wind. We've given some thought to it already, I think the industry's dabbled in it," he says.

Some hope for wind derivative marketers lies in the fact that gas turbine operators face huge running costs to keep their turbine warm and connected to the grid. If wind-generated power keeps coming onto the grid for longer than expected, they suffer financially by not being able to sell into the grid.

"There were units that were running at a higher capacity factor because there wasn't wind, and now when wind gets in their way, they're not paying down the debt like they used to, whether they're project financed, or rate-based with a utility. So I do think there are some offsetting positions," says Grundmeyer.

But some industry observers question whether the necessary sophistication exists. Thermal generators already have so many issues to deal with, in demand, timing, and the cost of bringing particular facilities online, that managing the additional aspect of wind availability might seem a stretch.

However, in contrast to commodities, wind risk doesn't need to be a genuine two-sided market to take off, according to Jeff Hodgson, president of the Chicago Weather Brokerage. "The speculators are the ones that will make the market, that will get the thing off the ground," he says.

Bigger picture

Beyond the question of how wind speed risk is shared out between developers, utilities, and lenders – through derivatives or otherwise – the larger question is how to deal with it on a grid level as wind expands as a proportion of total generation.

Already in several developed wind markets, wind power is being curtailed – that is, shut off from the grid – during peak output and times of low demand. This is causing huge controversy in the US Pacific northwest, where wind now makes up approximately 30% of the installed capacity in the Bonneville Power Administration's (BPA's) Balancing Authority Area.

"Because we are having a high hydro year here and because wind blows mostly at night, BPA has more energy than it knows what to do with overnight when load is low," says William Holmes, partner at law firm Stoel Rives in Portland, Oregon. "As a result, it is curtailing thousands of MWh of wind energy, forcing generators to lose the sale plus a $22 tax credit on each MWh curtailed. This is a foretaste of what will happen elsewhere in the US as variable energy resources like wind and solar achieve higher penetrations."

These curtailments are expected to cost US wind power operators approximately $50 million in 2011 alone. In June, Iberdrola Renewables, PacifiCorp, NextEra Energy Resources, Invenergy Wind North America and Horizon Wind Energy filed a complaint with the Federal Energy Regulatory Commission (Ferc), alleging that BPA unfairly discriminates against wind power. BPA denies these charges.

By contrast, when wind output was curtailed in Scotland in April this year, wind generators were fully compensated.[1]

"The issue has tended to be you've had days with high wind, so lots of wind generation in Scotland, when demand has been low – especially in the middle of the night," says Stewart Larque, spokesperson for the UK's National Grid in London. "But there's not enough capacity in the transmission system to move that power south of the border. So we're looking basically at those bids and offers, and we pick the most cost-effective way to deliver what we need. And in that case it meant we needed to reduce wind generation in Scotland."

However, in Germany, wind is required by law to be put into the grid first. Under the *Renewable Energy Sources Act* transmission systems operators (TSOs) are legally required to purchase and transmit all available electricity from renewable generation installations such as wind. Therefore, variable sources, including wind and solar power, are not curtailed for economic or operational reasons, only when the stability of the grid is at stake.

However, even these security of supply situations are gradually becoming more frequent in Germany because of grid constraints, especially in the north.

To deal with transmission constraints, the US, Germany and the UK, amongst others, are investing heavily in transmission system capacity expansion projects.

"In the coming years, as those reinforcements kick in, that will reduce the extent to which constraints in the transmission system are an issue," says the National Grid's Larque. "It will be easier to move the power in Scotland south of the border to those big demand centres in England."

But alongside such capacity increases, wind's share of the UK's electricity generation will also increase, and the National Grid expects forced curtailments to continue, caused less by a lack of regional transmission capacity, than by national-level technical energy balancing considerations.

A report released by the National Grid in June warned of the possibility of increasing curtailments of wind power at peak times. "…it will become increasingly necessary to restrict the output from wind generation onto the system to ensure sufficient thermal capacity is synchronised to meet the technical requirements of operating reserve. Under this scenario it is estimated that it may be necessary to curtail wind output on about 38 days per year by 2020," it says.

To avoid this wasteful and unsatisfactory outcome, the race is on to build more interconnectors, allowing leading wind countries to export power during times of peak production. Another solution lies in more advanced methods of energy storage. Pump storage via hydropower is already operational in many countries, and there are potential new technologies in everything from compressed air to giant flywheels.

The storage and transmission capabilities of a smart grid are obviously needed, but such projects are costly. This year, The Electric Power Research Institute, a non-profit R&D organisation, estimated the net investment needed to upgrade the US to a smart grid at between $338 billion and $476 billion.[2]

Until these technologies are scaled up, there will remain hard questions about who should pay the cost of over-production during peak wind times, and there is a distinct lack of academic research on how curtailments could affect wind as an investment proposition, as generation capacity expands.

In the US Pacific northwest, increased wind capacity could, counterproductively, lead to growing financial disincentives to wind operators, depending on the Ferc's decision. In the UK and Germany, wind variability costs will probably be passed on to consumers as a whole, as negative prices become more common.

Unless the regulatory framework gets it right, there could be serious drawbacks to investing in additional wind capacity, hampering efforts to achieve low-carbon power generation worldwide. ■

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[1] This happened through a mechanism in which every half-hour, each generator submitted bids and offers for the following hour, indicating what payment they would require to generate less power than planned, and what they would pay to generate more than planned

[2] Although it estimates the net present value of such a system in terms of reliability, capacity and environmental benefits, is between $1.2 trillion and $2 trillion.

Renewable Energy Generation's High Haswell wind farm in County Durham, north England