CORNWALL INSIGHT

CREATING CLARITY

Wholesale Power Price Cannibalisation

Energy Spectrum Analysis

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About the author

Tom is experienced in designing, delivering and assuring complex modelling projects.

At Cornwall Insight, Tom has:

- Led the development of a power market model
- Supported a major local authority in its financial modelling of the retail market
- Led the development of bespoke modelling for a range of customers, including for pumped storage, battery storage and gas peaking plant

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1 Executive summary

By the 2030s reductions in achievable wholesale power revenues at times when there is high renewables output will challenge the delivery of subsidy free wind and solar power projects.

The value earned from wholesale power is going to become increasingly important for renewables investments as subsidies are being steadily withdrawn. The Renewables Obligation (RO) closed to new investment in April 2017, the Feed-in-Tariff (FiT) scheme looks set to follow suit in April 2019 and there is only a limited £557mn (2012 values) being made available for the allocation of Contracts for Difference (CfD) in upcoming auctions. Our insight paper, "Static Electricity: New Accounting Controls for Low Carbon Levies[1]", argued that if current policy objectives prevail, there will be no new subsidy opportunities ahead of 2025, and possibly for several years after that.

But additional capacity is required to offset up to 18GW of decommissioning thermal plant. It may also be required to meet growing electricity demand from electrification of transport and heat. Furthermore, substitution by low carbon generation is required to continue reducing carbon emissions. The legally binding carbon budgets may yet be tightened, meaning continued efforts to reduce emissions is required in the power sector and not just heat and transport. In April 2018 Minister of State at the Department for Business, Energy and Industrial Strategy Claire Perry announced that the UK should explore a goal of having net zero carbon emissions by 2050, which would mean going much further than the existing ambition to reduce carbon emissions by 80% from 1990 levels.

It looks increasingly likely that renewables will need to be a significantly larger proportion of the generation mix, as emphasised by projections in National Grid's Future Energy Scenarios[2] (FES). But alternative sources of predictable revenue to make up for lost subsidies are not currently available. Reforms to the Capacity Market include plans for the participation of renewable generation but de-rating factors for intermittency will substantially limit potential value. Therefore, new renewable projects will increasingly look to the wholesale power markets to underpin investment.

1 https://www.cornwall-insight.com/newsroom/all-news/low-carbon-levy-costs-to-peak-later-than-government-expects
2 http://fes.nationalgrid.com/

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We already see price cannibalisation in the current market, but subsidised plant gets some respite from it.

A complicating factor will therefore be price cannibalisation. This is the depressive influence on the wholesale electricity price at times of high output from intermittent, weather-driven generation such as solar, onshore and offshore wind. The absence of fuel costs makes these generators competitive in wholesale markets when they operate, with high volumes of production squeezing out capacity from less efficient and higher cost conventional plant.

This results in lower cost, more efficient thermal plant setting prices, and sometimes periods where no thermal plant is operating in the market at all. The effect is therefore low or sometimes negative wholesale power prices, correlated to high levels of output from one or more intermittent sources of renewable generation. The greater the fraction of output on the system to meet demand from intermittent generation at any given time, the greater this effect becomes.

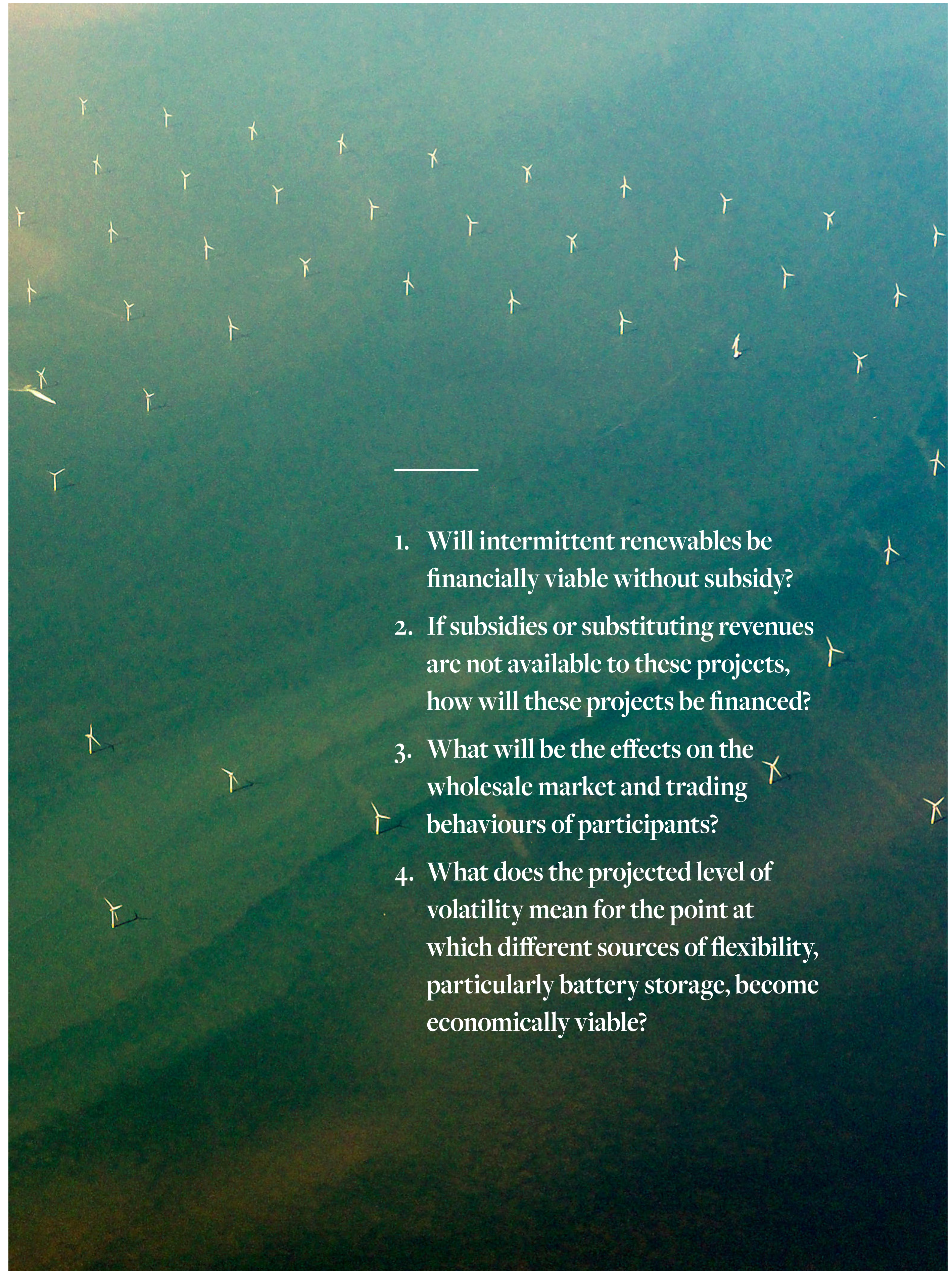
We already see price cannibalisation in the current market, but subsidised plant gets some respite from it. Generation accredited under the RO receive predictable value from other sources which are more than their Operation and Maintenance (O&M) costs, allowing them to generate revenue even if achieved wholesale power prices are less than anticipated at the point of investment. The CfD also insulates generators from falling prices. Incentives to reduce output within the CfD scheme only apply if prices go negative, with no subsidy paid after six consecutive hours of sustained negative prices. There is no such arrangement under the RO.

Our analysis shows price cannibalisation will become more prevalent. Excluding the nuclear plant at Hinkley Point C, CfD generation is expected to grow by as much as 14.1GW by 2025, which includes plant with a CfD but yet to commission and potentially 8.6GW of offshore wind that could secure contracts in the upcoming auctions. This further intensifies the price cannibalisation effect.

The results raise several key questions for the industry and policy makers alike about the ambitions to deliver the maximum capacity of low carbon generation at the lowest possible cost.

1. Will intermittent renewables be financially viable without subsidy? Costs for developing projects continue to fall but as we demonstrate, so could available revenues. This is most acute for onshore wind without access to CfD auctions but will also affect solar projects.

2. If subsidies or substituting revenues are not available to these projects, how will these projects be financed? The established project finance model relies on a combination of fixed or floor prices in Power Purchase Agreements (PPAs) and



Each generator will have its own marginal price based on a range of factors such as efficiency

subsidy to ensure debt can be covered. A volatile market and subsidised wind cannibalising the prices will reduce the level of floor prices. Investing against lower floor prices or increasing reliance on wholesale power revenues will see costs of capital increase. It will also potentially deter project finance lenders. Is there a role for government to design measures that correct this market failure?

3. What will be the effects on the wholesale market and trading behaviours of participants? Our analysis presents a wholesale market with increasing price volatility as the sources of dominant supply switch between 'must run' subsidised generation and flexible, short-run marginal price-based generation. This creates a high-risk environment with significant implications not just for generators, but for all parties including off-takers, suppliers, end-users and the System Operator (SO). With so much activity being focussed to the periods close to delivery the forward market cannot provide sufficient hedge for those that require price certainty and stability.

4. What does the projected level of volatility mean for the point at which different sources of flexibility, particularly battery storage, become economically viable? And in the case of battery storage at what stage can it viably play a role in mitigating cannibalisation effects for intermittent renewable generators?

This paper is the first in a series on related topics on the future of market and policy arrangements for continued efforts to further decarbonise the sector, in which we will present analysis in response to these questions.

2 Merit order

Electricity prices are determined by the marginal price for producing power, or in other words the most expensive source of generation required to meet demand during a period.

Each generator will have its own marginal price based on a range of factors such as efficiency, location and fuel costs for fuelled stations. These are typically referred to as Short Run Marginal Costs (SRMC). A range of generation types will typically be utilised to meet demand and they will dispatch in ascending order according to their marginal price. This creates what is called the Merit Order.

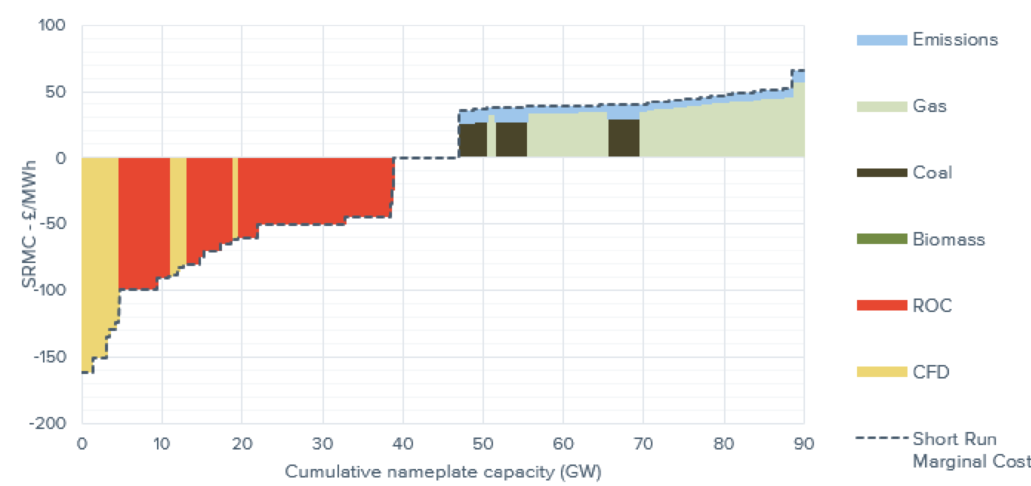
Renewable generation from wind, solar and hydro, has no fuel costs and relatively low O&M costs. They therefore have marginal costs close to zero. When subsidies that these plants receive are factored in to a consideration of wholesale prices at which they can generate to meet their SRMC, it shows that negative prices can be comfortably sustained.

The renewable subsidy-adjusted GB merit order for major generation categories as of April 2018 is shown in Figure 1. This includes renewables capacity at the various subsidy levels from the RO and CfD, and emissions costs from the EU ETS (including Carbon Price Support) for fossil fuel generators. This merit order represents the prices at which generators can theoretically operate to meet their marginal costs and demonstrates the current division of GB capacity into distinct categories of operation.

Subsidised renewable capacity from the RO and CfD is above 38.5GW. Capacity shown with zero SRMC refers to nuclear plant which is also "must-run" and relatively inflexible.

Figure 1: GB merit order, April 2018

Source: Cornwall Insight



Price cannibalisation describes the effect on wholesale prices where large volumes of ‘must-run’ power plant continue to operate during periods of oversupply from generation and/ or low demand.

3 Price cannibalisation and renewable subsidies

Price cannibalisation describes the effect on wholesale prices where large volumes of ‘must-run’ power plant continue to operate during periods of oversupply from generation and/ or low demand. The effect is most marked during periods where there is a predominance of output from subsidised, intermittent renewable generation. As these technologies have no fuel costs and low operating costs they have comparatively low SRMC and can out-compete fuelled plant. This results in high cost, inefficient thermal plant being squeezed to the margins, with cheaper more efficient thermal plant setting the price, or possibly all thermal plant being pushed out of merit. The result is very low or even negative prices at times of high intermittent renewable generation.

The renewable subsidy schemes operating in the GB market provide generators with revenue based on volume of electricity produced, providing a simple prerogative to maximise output. No subsidy is paid when the generator is not producing, hence there is an opportunity cost for not generating.

The incentive is therefore to continue to produce when the market is otherwise oversupplied and the wholesale price falls and even to continue to do so if prices turn negative up to the point that this reaches subsidy revenue. The strength of this incentive, and the wholesale price ranges in which it applies, depends on the value of the subsidy received and the scheme under which it is paid.

3.1 Subsidy schemes

Four subsidy schemes to encourage the development of renewable and low carbon generation have been in place in GB since privatisation. The first, in the 1990s was the Non-Fossil Fuel Obligation (NFFO) that was superseded by the RO in 2002 after which the FiT (2010) and the CfD (2014) were introduced.

Despite the imminent closure of the RO and FiT to new investment and the imminent hiatus in new budget being made available under the CfD scheme, subsidised renewables capacity will continue to grow as projects that met the scheme deadlines are brought through to deployment between now and 2025. In 2018 projects under these schemes account for 32% of total GB capacity increasing to reach 44% by 2025 and delivering 40% of GB annual demand[3], as shown in Figure 2.

The major capacity developments are from the RO and CfD and we concentrate on these two schemes for this section of the report.

The development of renewable capacity operating under subsidy is shown in Figure 3. New capacity under the subsidy schemes is growing at a relatively modest 1GW per annum through to 2023 comprising the final few projects accredited under the RO and those successful in the last CfD auction in 2017. The rate of growth is expected to pick up again following the next CfD auction in spring 2019, although the timing of deployment for new projects under the CfD is uncertain at this stage. We include Hinkley Point C nuclear capacity for 2025, noting though that there is considerable risk of delay.

3 National Grid, Future Energy Scenarios. Slow Progression

Figure 2: Current GB capacity ratio by renewables subsidy 2018 and forecast for 2025

Source: Cornwall Insight

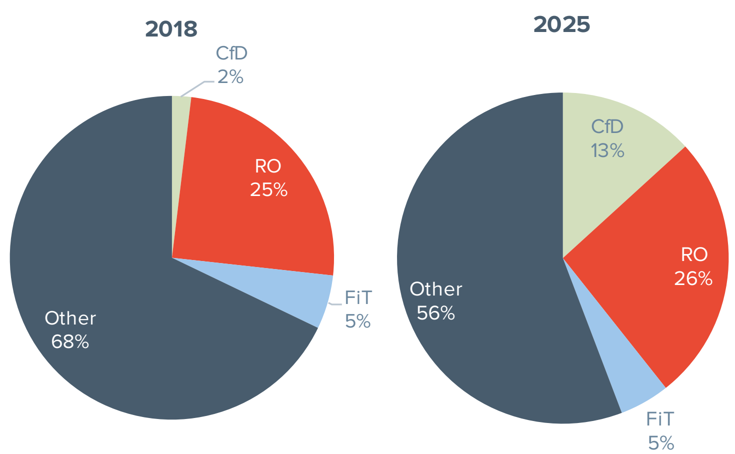
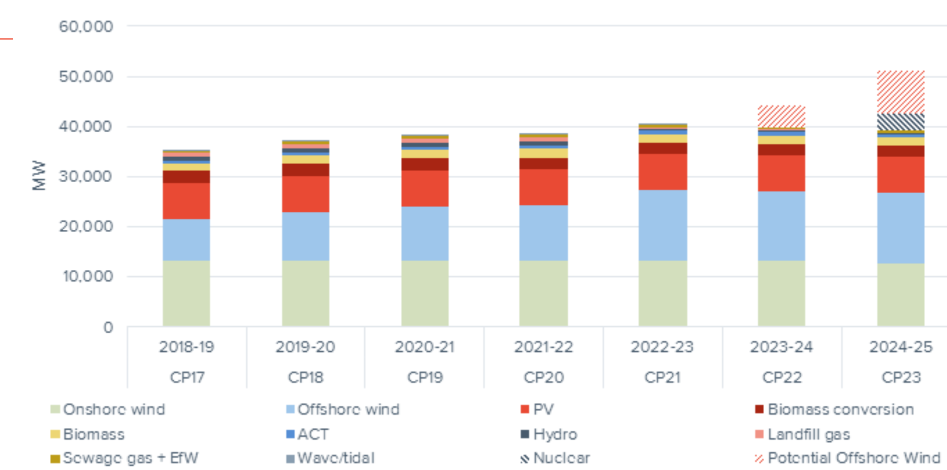


Figure 3: Development of renewable capacity operating under RO & CfD

Source: Cornwall Insight



> Onshore wind is estimated to have operating costs of £5.00/MWh. As a result, selling power at notional prices as low as -£42.22/MWh would earn sufficient revenue to cover costs.

3.2 Renewables Obligation

The RO has enabled almost 30GW of renewable generation to be deployed in the period since its inception in 2002 until it finally closed to new investment in 2017. The last projects to qualify are being deployed during 2018 and will take peak total capacity for the scheme to 31.5GW, of which 12.5GW will be onshore wind, 7.1GW offshore wind and 6GW solar.

Although payments under the RO are not linked to wholesale prices, the relative stability of Renewable Obligation Certificate (ROC) values in recent years has meant that RO generators have a high degree of subsidy revenue certainty. For example, a renewable generator in receipt of 1 ROC for each MWh of output in May 2018 will receive an additional £47.22/MWh[4] to the wholesale price.

Onshore wind is estimated to have operating costs of £5.00/MWh[5] according to government assessments. As a result, selling power at notional prices as low as -£42.22/MWh would earn sufficient revenue to cover costs, and so operating at prices down to these prices levels may be financially tolerable.

For some technologies, the ability to withstand negative prices without loss-making is even more robust. Plant accredited under the RO have been awarded banded levels of subsidy since 2009[6]. Some offshore wind plant for example receive 2 ROCs/MWh and taking into account O&M costs at £3.00/MWh[7] means there is no incentive to curtail output until prices fall below -£90/MWh.

The first ground mounted solar power projects under the RO are in receipt of 1.6 ROC/MWh, worth £75.55/MWh for 2018-19 with zero variable O&M costs[8].

3.3 Contracts for Difference

Excluding Hinkley Point C, there is 9.8GW of projects supported by committed contracts under the CfD, and investment contracts (the early form of CfDs). Of these, 7.5GW is offshore wind, 0.7GW onshore wind, 1.5GW biomass and CHP, 0.02GW solar PV and 0.12GW fuelled renewable stations.

Under the CfD scheme generators are awarded contracts with a strike price that guarantees an inflation-linked revenue (£/MWh) for the volume of power generated. The revenue received by stations is the sum of a wholesale market reference price and, where this falls below the agreed strike price, a top-up payment to the strike price recovered from consumers by electricity suppliers. Where the market reference price exceeds the strike price a generator will pay back the difference, thus capping the cost to the consumer.

There are two wholesale market reference prices. The Baseload Market Reference Price (BMRP) applies to fuelled renewable technologies. The BMRP is set at two points for each year, one for winter (October through March) and one for the summer (April through September). The prices are calculated from the average of baseload prices for that season, published by LEBA (London Energy Brokers Association), in the six months prior to the start of delivery for that period. This provides a single, fixed price for all output produced for that season.

The other is for intermittent generation, the Intermittent Market Reference Price (IMRP), and is calculated on an hourly basis using results from the N2EX day-ahead auction.

Generators with a CfD are incentivised to continue production during low or even negative prices. Payments under the CfD were initially capped at the strike price so the top up is made from a minimum market reference price of £0/MWh. Therefore, should market reference prices become negative, the generator does not receive the full difference between the reference price and the strike price.

Depending on the strike price, this still gives substantial insulation to low and negative prices before loss-making occurs. To exemplify, the offshore wind station Hornsea 2 received a strike price of £57.50/MWh (2012 prices) in the second CfD allocation round for delivery year 2022-23. It will receive £57.50/MWh unless prices fall below zero. Even then, it would only begin to accumulate losses to the extent that the net sum of negative prices and operating costs exceeded the £57.50/MWh received under the CfD, necessitating a negative price of around £54.50/MWh.

This is the least extreme case. The capacity weighted average offshore wind strike price across all CfDs is £109.44/MWh in 2012 money. Meaning the loss-making point for an average CfD offshore plant would be a negative price in the region of –£106/MWh. Of course, investor returns will begin to suffer before these breakeven cashflow points, but the analysis is indicative of the underlying resilience to negative prices.

From 2016 additional measures were adopted in the CfD to comply with its State Aid approval. These measures specified that CfD payments would be reduced to zero following six hours of consecutive negative prices. This is a high threshold of negative pricing occurrence before subsidy payments are stopped.

4 This is the RO "buy-out" price.
5 https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/566567/BEIS_Electricity_Generation_Cost_Report.pdf
6 https://www.gov.uk/guidance/calculating-renewable-obligation-certificates-rocs
7 https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/566567/BEIS_Electricity_Generation_Cost_Report.pdf
8 https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/566567/BEIS_Electricity_Generation_Cost_Report.pdf

Should CfD market reference prices become negative, the generator does not receive the full difference between the reference price and the strike price

3.4 Relative exposure to low prices

Figure 4 demonstrates the respective revenue and cash curves for example projects under each scheme relative to changes in wholesale power prices.

For a RO project, revenues vary in direct relation with changes to the power price allowing for increased cashflow at higher wholesale prices. A positive cash flow remains as prices fall, continuing even at negative prices to the value of the subsidy less O&M costs.

In contrast, CfD projects maintain consistent positive cash flow irrespective of power price movements until prices turn negative. Where power prices are negative, the subsidy is paid up to the level of the strike price, calculated from £0/MWh. Should the day-ahead auction return six or more consecutive hours of negative prices however, the subsidy is removed altogether, and no payments are made for those periods.

3.5 Routes to market

Figure 5 illustrates the different roles that generators and off-takers play in bringing power to market under different subsidy regimes.

RO projects have several routes to market options as subsidy revenue is not directly linked to wholesale markets. This allows for a range of different strategies to sell power using the available market indexes, such as forward seasons, quarters and months as well as the day-ahead index.

Figure 4: P&L charts for example RO and CfD projects

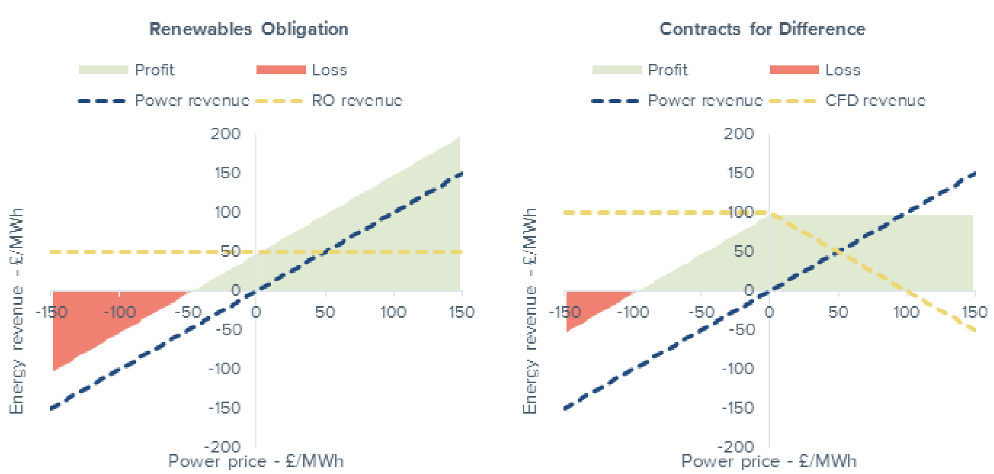
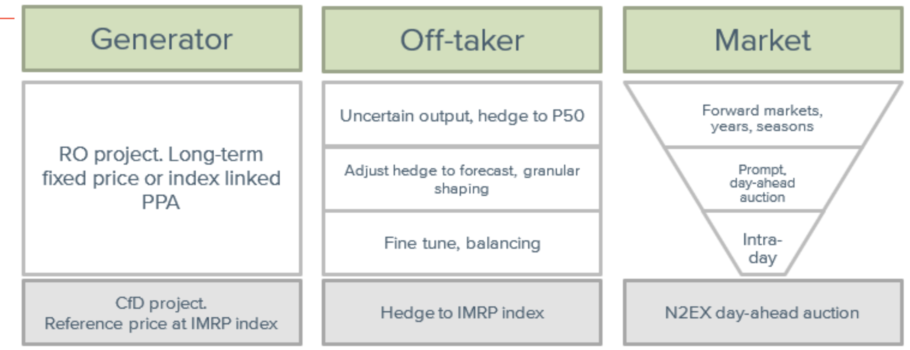


Figure 5: PPA and hedging options for RO and CfD

Source: Cornwall Insight



RO generators typically seek revenue stability and look for long-term PPAs of 10 to 15 years duration with fixed wholesale prices, or more commonly floor prices index-linked to forward seasonal contracts.

The generator is also likely to incur a risk fee to the off-taker for managing the variable output of the projects in the market. Other PPA structures use a mixed approach, hedging at different times for greater price flexibility. Off-takers managing RO projects therefore have the option to adapt hedging strategies to seek the best market value.

As section 6 illustrates the cannibalisation effect from growing levels of CfD generation will be greatest on the day-ahead index.

A RO generator selling their power earlier, at the month-ahead or week-ahead stage for example, would allow capture of some value from the uncertainty in wind forecasts even if this also results in larger discounts from off-takers for accessing less liquid markets, or needing to manage imbalance more actively.

The CfD contract will drive the use of specific indexes, the BMRP and the IMRP. CfD operators will look to achieve a capture price (i.e. the actual price achieved) as close as possible to the relevant market reference price through selling their output in the markets where the index is set in order to achieve their strike price. Where this is different to the index it creates price risk for the generator whereby if the hedged price is lower than the index the top-up revenue will not cover the difference to the strike price.

Negative prices prevalent in Germany

Renewable generation in Germany reached 36.1% across 2017 and at 6am, New Years' day 2018, accounted for 100% of power consumption. Throughout 2017 there were a total of 146 hours of negative prices with an average price of -€27/MWh. This was double the number of hours recorded in 2016. However, the lowest price was -€83MWh, less extreme than the previous year when it reached -€130MWh. (Source, Cleanenergywire.org)

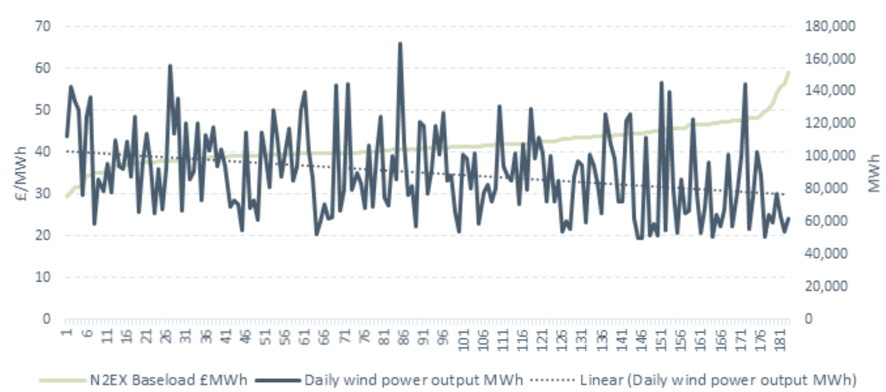
This is shown in Figure 6. An example intermittent CfD generator achieves a capture price of £50/MWh relative to an IMRP of £55/MWh, resulting in a top-up that falls short of the strike price of £75/MWh.

Figure 6: Example capture price v IMRP shortfall (illustrative figures)

Source: Cornwall Insight

Figure 7: Inverse relationship between N2EX day-ahead price and wind power output, summer 2017

Source: Cornwall Insight
Data from N2EX, Elexon



4 Cannibalisation in the current market

4.1 Current effects

At the current level of renewables penetration, the price cannibalisation effect varies by season and in relation to the shape of demand. During the winter plant with relatively high SRMC continues to be required to meet demand. For example, during the recent extreme cold weather brought about by the 'beast from the east', wind power operated at near maximum output over extended periods at up to 13GW, yet day-ahead prices for baseload were as high as £98/MWh (1 March 2018).

However, at periods of lower demand during summer, and in milder, windy spring and autumn periods the price cannibalisation effect is more readily identifiable. Figure 7, compares the N2EX day-ahead auction price and wind power output during all days of summer 2017 demonstrating a developing inverse relationship between wind power output and market price. The green line shows the distribution of N2EX day-ahead auction prices over the period. The blue line illustrates the wind power output for the same periods and the linear trend line is the inverse relationship.

4.2 Sensitivity to further renewables deployment

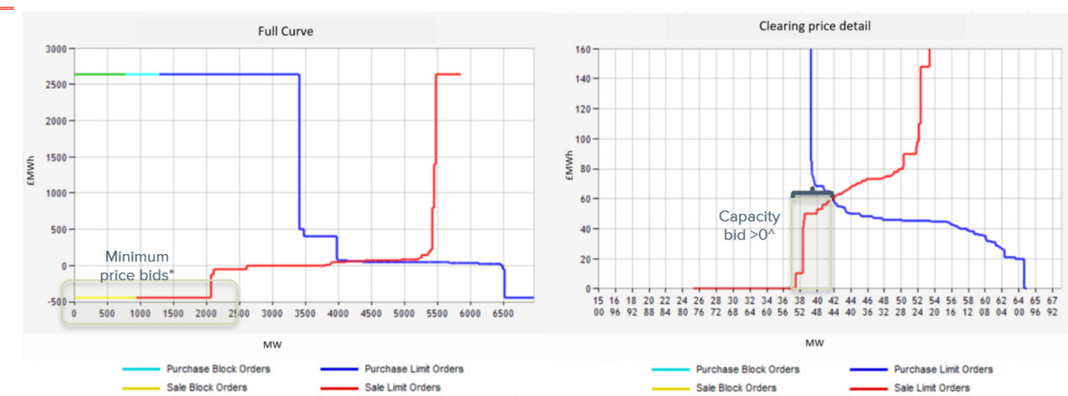
A close look at the merit order in action also highlights the sensitivity of the market to increased price cannibalisation. The examples in Figure 8 are from the day-ahead auction run by EPEX (European Power Exchange) in GB. They show the prices at which sellers (supply) and purchasers (demand) were prepared to buy and sell for given volumes for a one-hour delivery period on 11 May 2018, but which are typical for most periods throughout the year.

The chart on the left shows all the bids and offers submitted for the period. On the right-hand side, we take a close-up view of the same period at the point of marginal price setting, where the curves intersect.

The full supply curve (in yellow/red, left-hand chart) shows >2,000MW bidding to generate at the minimum auction price of -£500/MWh*, 500MWh bidding at below £0/MWh and a further 1,700MW bidding at £0/MWh. When we look at the close-up view (right-hand chart), we see the marginal price is set at £60/MWh for 4,244MW (point of intersection).

Figure 8: EPEX Day-ahead auction supply and demand curves

Source: EPEX Spot UK



At periods of lower demand during summer, and in milder, windy spring and autumn periods the price cannibalisation effect is already more readily identifiable.

Of the generation clearing the auction (red line), only ~450MW bid above £0/MWh^. In other words, only 450MW of generation would need to have been displaced to arrive at zero or negative prices.

The negative bidding of prices is not limited to renewable generators. Inflexible conventional plant will also be willing to pay to generate to avoid the costs of shutdown or start-up in the expectation that prices will be positive in subsequent periods.

The spread between the volume of buy and sell also indicates a market primed for low or negative prices as renewables grows. Figure 9 illustrates the average daily volumes for offers (Buy) and bids (Sell) each month during 2017 and shows the market was short by 16.6% on average over the year.

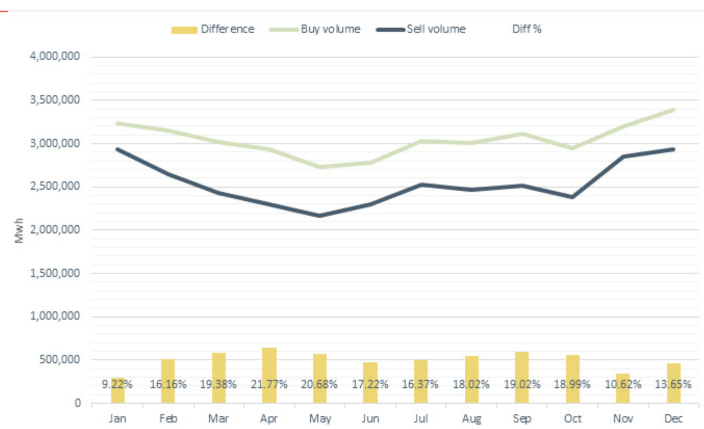
If additional output of 56TWh from offshore wind under the CfD enters the auction, as our modelling suggests is possible based on currently committed projects and potential from the existing budget for future auctions (£557mn), then this increases volumes on the sell-side of the market.

We estimate that this will narrow the bid/offer spread volumes by up to 75% on days of high wind output, significantly increasing the potential for instances of low or negative prices, unless there is the corresponding increase to volumes on the buy-side to off-set this effect that is able to match the pattern of high wind output.

The GB market will be one of the first to experience this phenomenon with few equivalents from liberalised markets around the globe. The most similar is Germany where renewable deployment is ahead of ours and where negative day-ahead prices are increasingly common in the auctions.

Figure 9: N2EX daily liquidity, Jan-Dec 2017

Source: Cornwall Insight
Data from N2EX



5 Long term market outlook

5.1 The changing generation mix

Cornwall Insight has modelled the price impacts of increasing subsidised intermittent renewable output using the underlying assumptions from National Grid's Future Energy Scenarios (FES), Slow Progression case. This scenario most closely matches the current developments based on the existing policy framework and prevailing market conditions with relevance to wind capacity, both onshore and offshore.

Figure 10 shows the evolution of the generation mix to 2040 under the Slow Progression case as capacity increases with significant contributions to total capacity from wind and solar to >140GW. Gas-fired generation capacity dwindles from 29GW to 10GW by the end of the period with nuclear power growing by only 1GW. Peak demand over the period however, increases by only 3GW, emphasising the requirement for flexible generation to cover periods of low renewables output.

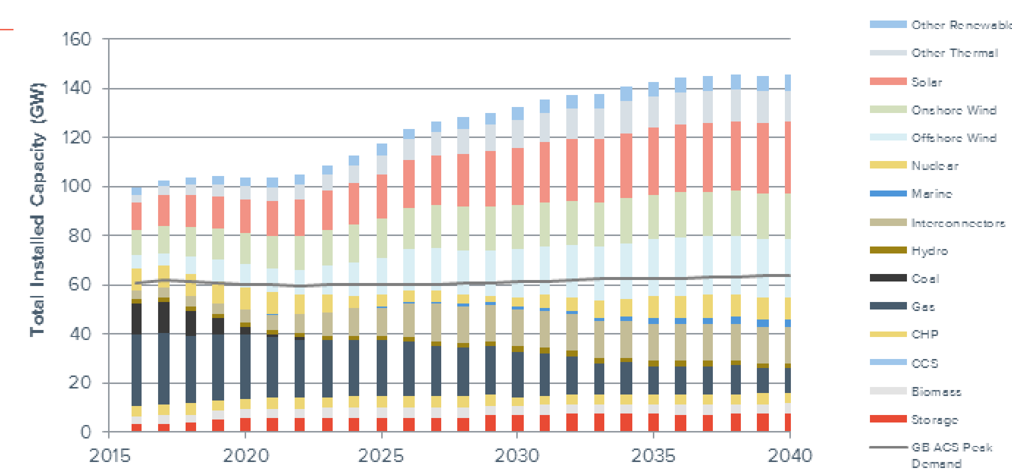
Figure 11 shows the increasing annual volume of renewable output and the growing proportion of total generation which comes from renewables. By 2035 the FES Slow Progression scenario shows renewables producing 196TWh per annum, accounting for 56% of all generation output.

By 2035, offshore wind power becomes the second largest technology by capacity (23.4GW), behind solar power (27.1GW) but significantly, the largest by output at 87TWh, four times that of solar. Onshore wind grows more modestly, but still increases to 18GW capacity with output of 41TWh.

However, there is a mismatch between the scenario for renewable capacity and what subsidy schemes will deliver. Capacity accredited or in receipt of subsidies amounts to 14GW of offshore wind, 13GW of onshore wind and 12GW of solar capacity. The next CfD auctions are expected to favour offshore wind through the allocation of budget and auction design.

Figure 10: Total installed capacity under FES Slow Progression

Source: Cornwall Insight
Data from National Grid



There is a mismatch between the scenario for renewable capacity and output and what subsidy schemes will deliver.

It is possible that the £557mn (2012 money) that will be spent could deliver an additional 8.6GW of offshore wind capacity, giving a total of 22.5GW for this technology, marginally short of the Slow Progression 2035 estimate.

This leaves capacity shortfalls for onshore wind and solar of 14GW and 6GW respectively, unless for both technologies subsidy free developments can close the gaps.

5.2 Increasing volatility

Using the Slow Progression generation mix, our modelling calculates the levels of out-turn prices to half-hourly granularity on the intra-day market, presenting a strong indicator of the merit order and marginal price effects of subsidised output.

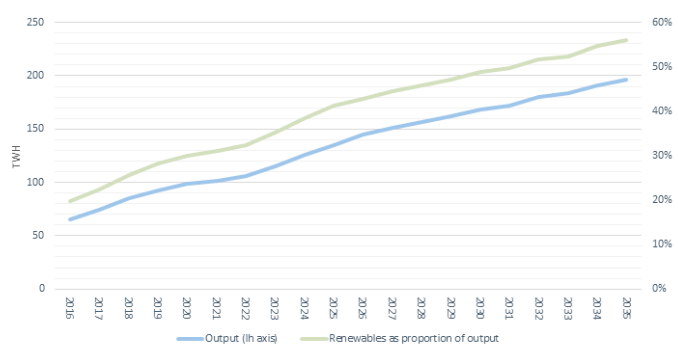
A striking outcome from the modelling is an increasing frequency of very low and negative prices over time as the proportion of intermittent capacity on the network increases. The modelling also demonstrates an opposite effect, which is the increasing frequency of price spikes as the market switches back to conventional and flexible plant when wind and solar output fall.

We classify spikes to be periods when prices are £120/MWh (2018 money) or greater, based on the approximate levels for dispatching short duration Open Cycle Gas Turbine (OCGT) plant.

Figure 12 charts the frequency of very high and negative pricing, increasing steadily until 2023 after which the incidence grows markedly as new offshore wind capacity is deployed. Negative prices account for 13.5% of out-turn periods and prices equal to or greater than £120/MWh for 9% all out-turn price periods in 2034, compared to 0.04% and 1.4% in 2018-19 respectively.

Figure 11: Total renewable output and proportion of GB supply

Source: Cornwall Insight
Data from National Grid



Price volatility is generally seen as a positive feature for traded markets, providing opportunities to increase revenues. For investors in flexible plant and energy storage, increased volatility creates greater arbitrage value. This situation may see an acceleration in co-located batteries, but unless commercially viable longer-duration storage can be deployed this is unlikely to off-set the cannibalisation impact for a wind farm or solar operator.

During the modelled period the market makes regular transitions from periods of generation dominated by subsidised output to periods where higher marginal cost flexible plant is required to meet demand.

Figure 13 shows the progression of increasing price volatility relative to the out-turn baseload power price based on the standard deviation, or the increasing range of prices, from the average of outturn prices.

Figure 12: Annual frequency of <=£0/MWh & >=£120/MWh price periods 2018 through 2034

Source: Cornwall Insight

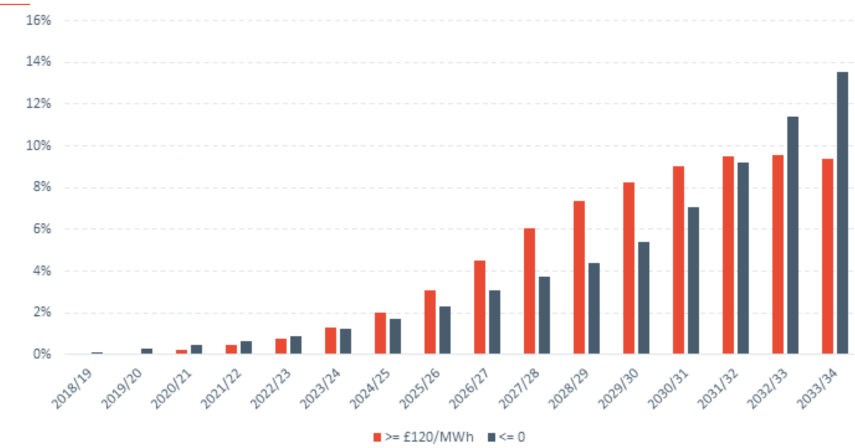
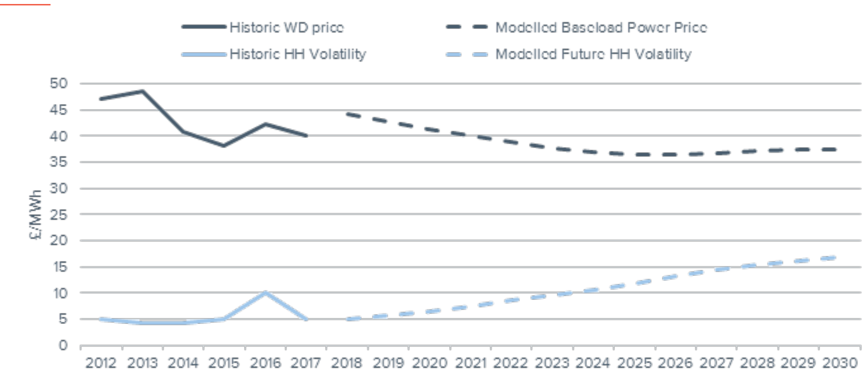


Figure 13: Historic and modelled power prices and volatility

Source: Cornwall Insight



Price volatility is generally seen as a positive for traded markets, providing opportunities to increase revenues.

Figure 13 highlights that price volatility has remained stable for much of the period since 2012. Prices were falling until 2015, when levels started to increase with a corresponding rise in the volatility. Our analysis shows that levels of price volatility are set to increase consistently from 2018 onwards. As intermittent generation capacity grows, the swings between high output from low cost renewables, and more expensive flexible capacity become more frequent.

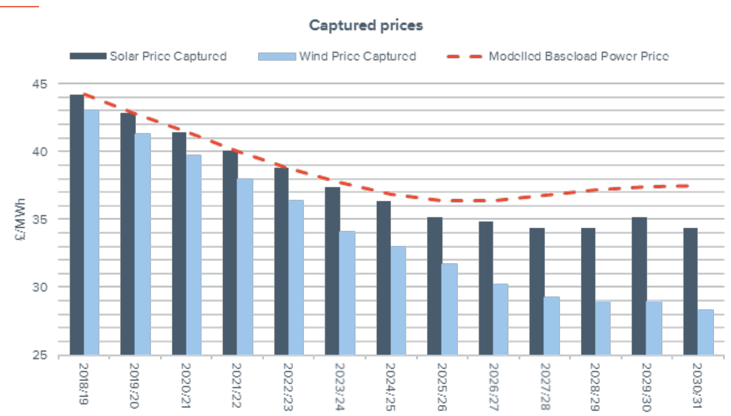
Volatility would usually be associated with increasing price and volume risk in an undersupplied market. That would in turn, push up forward prices to incentivise additional capacity. However, we think the market will be structurally well supplied but with regular swings between oversupply and shortfall. The aggregate effect is in favour of oversupply and therefore applies downwards pressure on forward wholesale contracts, as well as those close to delivery.

This pattern is indicative of the division of the marketplace into three elements:

1. Firstly, the flex market consisting of capacity following the traditional marginal pricing market process, with generators competing over position in the merit order and optimising for price efficiency.
2. Secondly, a largely subsidised renewables fleet, with their volumes shifting the merit order powerfully at times of high output.
3. Thirdly, should they develop, unsubsidised intermittent renewable plant that will turn-off once prices drop below their O&M costs. These plants will be having to do so more often than they would like compared to their subsidised peers due to the difference in incentives for RO and CfD generators.

Figure 14: Modelled capture prices for wind and solar power (2018 money)

Source: Cornwall Insight



5.3 Wind and solar power captured prices

For intermittent renewable projects, the increasing level of price cannibalisation begins to make a significant impact on their captured wholesale price. Wind and solar projects rarely achieve the prevailing baseload price over an extended period from their PPA in the current markets; a result of the output profile and the costs of risk and shaping from off-takers.

As capacity and output from these technologies increases and exerts a greater influence on the market not only does the cannibalisation effect impact the overall market price but capture prices are also eroded. This is shown in Figure 14.

Wind power output experiences higher levels of cannibalisation than solar power. This is caused by the magnitude of wind output relative to solar, and the potential for sustained high output, with output nationally operating at load factors greater than 50% for two or more consecutive days on 76 occasions during 2017.

This has implications for the costs of the CfD scheme as lower wholesale prices mean higher subsidy costs under the way the levy is constructed. Lower strike prices are anticipated in future auctions as costs continue to fall and technological advances improve efficiency. But, as we set out in our insight paper "Static Electricity: New Accounting Controls for Low Carbon Levies", we argue that lower strike prices will also result in a significant increase in capacity, which will in turn intensify the price cannibalisation impact for wind and raise levy costs overall.

For new wind projects and existing capacity losing access to subsidy (such as those coming out of the RO) the combination of falling wholesale prices generally, and lower captured prices, could damage their economic viability.

The cannibalisation effect for solar projects is less profound than for wind, but still significant. Solar power benefits from delivering most of its output during the peak periods (Monday-Friday, 07:00 to 19:00) when demand is high, and therefore we forecast it will track closer to baseload power prices until the mid-2020s as a result of a less dramatic merit order impact. After 2025 we predict a greater difference to the baseload price as the projected capacity under FES increases. The cannibalisation effect for solar and the propensity for zero or negative pricing is greatest at weekends (and bank holidays), and from May to October, when demand is lower and solar output is at its highest.

Solar power also enjoys some benefits from the increasing deployment of wind power. Solar output can capture higher prices during those daytime periods in the winter when wind output is low which acts to partially offset lower prices when there is good availability from both wind and solar. However, with consistent solar output during the summer months, the average reduction to capture prices is significant at between 10% and 20% lower across the year in 2031 relative to 2018. This is shown in Table 1.

Table 1: Captured price proportion to base load

	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31
Solar	100.0%	100.0%	100.0%	100.0%	100.0%	99.1%	98.6%	96.4%	95.7%	93.4%	92.4%	93.8%	91.7%
Wind	97.4%	96.5%	95.8%	94.8%	93.9%	90.5%	89.4%	87.1%	83.0%	79.6%	78.0%	77.3%	75.4%

Source: Cornwall Insight

The results raise several key questions for the industry and policy makers alike about the ambitions to deliver the maximum capacity of low carbon generation at the lowest possible cost.

6 Conclusions

Our modelling demonstrates the increasing impact to the wholesale market from price cannibalisation, driven by the increasing deployment of subsidised renewable capacity. All forms of subsidy for existing intermittent generation drive the cannibalisation effect. But the effect will intensify as the CfD scheme brings forward a concentration of offshore wind, the output from which will most likely be sold on the day-ahead market index. These CfD generators will be neutral to low power prices until they exceed top-up payments, or until there are six hours of consecutive negative pricing.

Through our analysis we have demonstrated that the cannibalisation effect acts to drive down wholesale prices overall and reduces the available capture price for intermittent renewables. This is true for projects under all support schemes but, due to the absence of subsidy payments, will particularly impact those that may be built subsidy-free. This runs the risk of deterring investment in these schemes in the first place.

For a representative 10MW onshore wind project, the combined effect of lower wholesale prices and declining capture rates is to reduce revenues from wholesale power revenues by 34% in 2031 compared to 2018. Our forecast illustrates that falling relative capture prices for wind power mean an effective commodity rate of £28.3/MWh in 2031 (nominal value, 2018), capturing 74.4% of the baseload power price.

Solar power is also significantly affected by cannibalisation. A representative 5MW standalone solar project will experience wholesale market revenues reducing 22% from 2018 by 2031. According to our modelling, solar power achieves an effective capture price of £34.4/MWh in (nominal value, 2018), capturing 91.7% of the baseload power price.

The results raise several key questions for the industry and policy makers alike about the ambitions to deliver the maximum capacity of low carbon generation at the lowest possible cost.

1. Will intermittent renewables be financially viable without subsidy? Costs for developing projects continue to fall but as we demonstrate, so could available revenues. This is most acute for onshore wind without access to CfD auctions but will also affect solar projects.
2. If subsidies or substituting revenues are not available to these projects, how will these projects be financed? The established project finance model relies on a combination of fixed or floor prices and subsidy to ensure debt can be covered. A volatile market and subsidised wind cannibalising the prices will reduce the level of floor prices. Investing against lower floor prices or increasing reliance on wholesale power revenues will see costs of capital increase. It will also potentially deter project finance lenders. Is there a role for government to design measures that correct this market failure?
3. What will be the effects on the wholesale market and trading behaviours of participants? Our analysis presents a wholesale market with increasing price volatility as the sources of dominant supply switch between ‘must run’ subsidised generation and flexible, short-run marginal price-based generation. This creates a high-risk environment with significant implications not just for generators, but for all parties including off-takers, suppliers and end-users and the System Operator (SO). With so much activity being focussed to the periods close to delivery the forward market cannot provide sufficient hedge for those that require price certainty and stability.
4. What does the projected level of volatility mean for the point at which different sources of flexibility, particularly battery storage, become economically viable? And in the case of battery storage at what stage can it viably play a role in mitigating cannibalisation effects for intermittent renewable generators?

We will be addressing each of these questions directly in future papers and comments during 2018, timing these to coincide with the government’s own review of the Electricity Market Reform mechanisms which commences in the summer.

About us

We bring innovation and differentiated capabilities that help you create value, deliver business outcomes and improve performance. Most importantly we ensure that you receive

- An impartial view – our opinions are based on facts, never biased or influenced by others
- An expert view – our analysis leverages the collective expertise of our team in comprehensive research, insight and training
- An integrated view – our research and insight integrates every aspect of the market to best cover an increasingly complex energy world

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