Winds of change: how high wind penetrations will affect investment incentives in the GB electricity sector

Will Steggals[a], Robert Gross[b], and Philip Heptonstall[b]

[a]SSE[1], Suite 197, Fifth Floor, 35 Grosvenor Gardens, London, SW1W 0BS; will.steggals@sse.com; 0783 7383386

[b]Imperial College Centre for Energy Policy and Technology and UK Energy Research Centre

ABSTRACT

Wind power is widely expected to expand rapidly in Britain over the next decade. Large amounts of variable wind power on the system will increase market risks, with prices more volatile and load factors for conventional thermal plant lower and more uncertain. This extra market risk may discourage investment in generation capacity. Financial viability for thermal plant will be increasingly dependent on price spikes during periods of low wind. Increased price risk will also discourage investment in other forms of low-carbon generation (e.g nuclear power), exacerbating financing difficulties resulting from their capital-intensity.

[1] NB. View do not necessarily reflect those of SSE.

A number of policies can reduce the extent to which generators are exposed to market risks and encourage investment. However, market risks play a fundamental role in shaping efficient investment and dispatch patterns in a liberalised market. Therefore, measures to improve price signals and market functioning (such as a stronger carbon price and developing more responsive demand) are desirable. However, the scale of the investment challenge and increased risk mean targeted measures to reduce (although not eliminate) risk exposure, such as capacity mechanisms and fixed price schemes, may have increasing merit. The challenge for policy is to strike the right balance between market and planned approaches.

Keywords: Wind power; Electricity market reform; Investment

1. Introduction

The electricity generation mix in Britain is set to undergo profound change as the sector decarbonises. In particular, the EU's renewable energy target may require up to 40% of UK electricity demand to be met from renewables by 2020 (DECC, 2009a). As the most cost-effective and scalable renewable technology in British conditions, wind is expected to provide the majority of this (ibid). However, due to its variability, this rapid expansion in wind will still need to be complemented by large amounts of flexible thermal capacity, to ensure demand can still be met reliably. The issues discussed in this paper are particularly relevant to Britain, which has a unique combination of a largely islanded system, an energy-only electricity market and high hopes for wind power. However, the issues discussed here have relevance to a wide range of countries, systems and regulatory approaches.

Britain's market (The British Electricity Transmission and Trading Arrangements, BETTA) is designed to maximise direct trading of electricity between suppliers and generators, with the National Grid Plc, the Transmission System Operator (TSO) only contracting for balancing services and taking actions through a balancing mechanism to maintain supply/demand balance close to real time. BETTA is an energy only market that does not offer any form of capacity payment and whilst the TSO monitors expected system margin over a range of timescales it is not responsible for directly commissioning capacity. A large penetration of wind will change the market conditions that conventional plants face. Since the overall capacity of the system will need to be higher to maintain reliability, *on average* there will be more spare capacity available and conventional plants will therefore be used less. For periods when wind output is high, wholesale power prices will be very low, and occasionally negative. Moreover, the variability and unpredictability of wind output will increase uncertainty over conventional plant usage patterns and the prices they will receive (Poyry, 2009; Redpoint, 2009).

For all these reasons, there are some concerns over the British market's ability to manage the risks associated with high penetrations of wind and whether investment in flexible capacity will be sufficient to provide an acceptable level of reliability. In recent years, policy-makers and regulators have increasingly recognised the profound effect that high penetrations of inflexible plant (particularly wind and nuclear) are likely to have on the electricity market (DECC, 2009; DECC,2010; Ofgem, 2010). At the same time, a number of commentators have argued that the required pace of low carbon investment other than renewables (nuclear and CCS in particular) will be difficult to achieve under the current market framework, given the risks currently associated with deploying capital intensive low carbon technologies. This has led some to postulate that a fundamental reworking of the electricity market framework may be needed (CCC, 2009; DECC, 2010; Gross et al, 2009; Ofgem, 2010).

The remainder of this paper provides a review and analysis of how high penetrations of wind power will affect incentives to invest in different types of electricity generation capacity. It focuses in particular on capacity adequacy (to maintain reliability) and the *nature* of capacity likely to be built under current market and regulatory conditions. Section 2 briefly reviews the main categories of market failure that may result in insufficient or inappropriate capacity investment and introduces the impacts of wind on such investment. Section 3 discusses the impact of high penetrations of wind on both average wholesale prices and on price volatility. Section 4 considers the relationships between prices, conventional plant load factors and likely investment decisions. Section 5 reviews the main options available to policymakers seeking to incentivise low carbon investment.

2. Investment under the current market framework

In an idealised electricity market, when supply conditions are tight price should rise until demand has been rationed off to meet supply. At the same time, the anticipation of tight supply conditions in the future (and consequent high prices) provides incentives for new capacity investment, as well as to extend the life of existing plants and bring old plant out of 'mothballs' (Collins et al, 2008). 'Scarcity rents' earned from the occasional high spot market and balancing market prices allow generating plants to pay their fixed costs within a financially viable timeframe (Adib et al, 2008). Risks around these investments can be managed through forward contracts as well as through vertical integration between generation and supply functions (Moran and Skinner, 2008). For all these reasons, in aggregate, generation firms can be expected to deliver sufficient capacity to meet peak demands with high probability. Indeed, since it was privatised in the 1990s, the British electricity system has been successful in promoting new capacity investment and maintaining reliability, with system margin consistently above the 20% figure often used as a proxy for capacity adequacy (Gross et al, 2006). However, there are a number of reasons why the electricity market may not always deliver the optimal level and type of investments to efficiently meet society's demands for both reliability and carbon emissions reductions:

- **Reliability as a public good.** A number of studies (Awerbuch et al, 1999; Helm, 2008; Lemming, 2003) argue that reliability has public good characteristics and that therefore it will be undersupplied by the market. In particular, reliability is 'non-exclusive' in nature: as one unit of capacity is added to the system, all consumers benefit from the increased reliability that the extra unit provides. This arises because (at present) suppliers lack the technology to disconnect many consumers individually in the case of inadequate supply (Lemming, 2003; Joskow, 2008). A complete market for reliability where consumers could pay for the level of reliability they desire cannot arise. A related issue is that the vast majority of electricity consumers are not exposed to prices in real-time. Real-time pricing would encourage consumers to respond to high prices at times of scarcity by reducing consumption, helping to match supply and demand with reduced need for peaking capacity (DECC, 2009a).

- **Market risk and cycles.** Investing in electricity generation capacity is risky for number of reasons. Prices are volatile due to the homogenous nature of electricity, its lack of storability, inelastic demand and the steepness of the supply curve as electricity production nears system capacity (Roques et al, 2005; White, 2006). This price risk increases uncertainty over project revenues, increasing the cost of capital, and discouraging investment. The 'lumpy' nature of investment in capacity (where a new plant can represent a significant and sudden jump in capacity) can also result in 'capacity oscillations' (Collins et al, 2009; Green, 2008). If a shortage of capacity begins to emerge, long lead times limit how quickly the market can respond (Redpoint, 2006). Moreover, during a period where capacity is becoming tight, and prices are rising, a number of companies may simultaneously decide to build new capacity. This may result in overcapacity when these plants come online years later, with consequent price falls.

- **Carbon externality**. A key market failure arises in the electricity sector if generators are not required to pay a price for the carbon they emit that is equivalent to the value society places on emissions reductions (Stern, 2005). At present the EU Emissions Trading Scheme (ETS) carbon price is both uncertain and significantly below this level which, all other things being equal, will lead to underinvestment in low carbon technologies (Newbury, 2009).

- **Learning externalities and technology 'lock-in'**. Investment in immature technologies can generate significant learning externalities meaning that without intervention the market will under-invest in these technologies. Furthermore, new technologies may not become cost-competitive until significant deployment of the technology has taken place. In the absence of perfectly functioning capital markets and foresight, new technologies may never achieve the market accumulation needed to be cost competitive without subsidies. This lock-in problem is particularly acute in the electricity sector as the homogenous nature of the product means that there are few niche markets where the technology can be developed with some shelter from established competition (Stern, 2005).

In addition to the reasons described above, changes in policy which cannot be predicted also result in significant regulatory risk for investment. The overall effect is that investment in generation capacity is risky and, in the absence of adequate financial instruments to manage risk, the market may undersupply capacity and consequently reliability. A key question is whether increased penetrations of wind will accentuate these factors. Low carbon technologies (e.g. wind and nuclear) have different characteristics to conventional generation. In particular, they are characterised by high capital costs and very low marginal costs whilst wind is also variable. This raises questions as to (i) how the market will operate with high penetrations of these technologies; and (ii) how well suited the current market framework is for supporting investment in these technologies.

3. How wind will change the electricity market

This section outlines how a high penetration of wind (around 30% in 2020) is likely to effect wholesale prices in the GB electricity market, assuming that the main functions of the market are left largely as they are today. We discuss two distinct aspects; impacts on average wholesale prices' and impacts on short term price volatility.

Average wholesale prices

Wind power is generated at near zero marginal cost and is therefore always dispatched when it is available. In the short-term, where the rest of the generating capacity remains unchanged, wind power therefore pushes high marginal cost plant out of the generating mix and wholesale spot prices are be depressed, especially at times when wind output is high. This 'displacement' effect is illustrated in Figure 1 where wind is characterized as reducing residual demand (because it is always dispatched).

Figure 1: The short-term impact of wind power on electricity prices (Author's illustration)

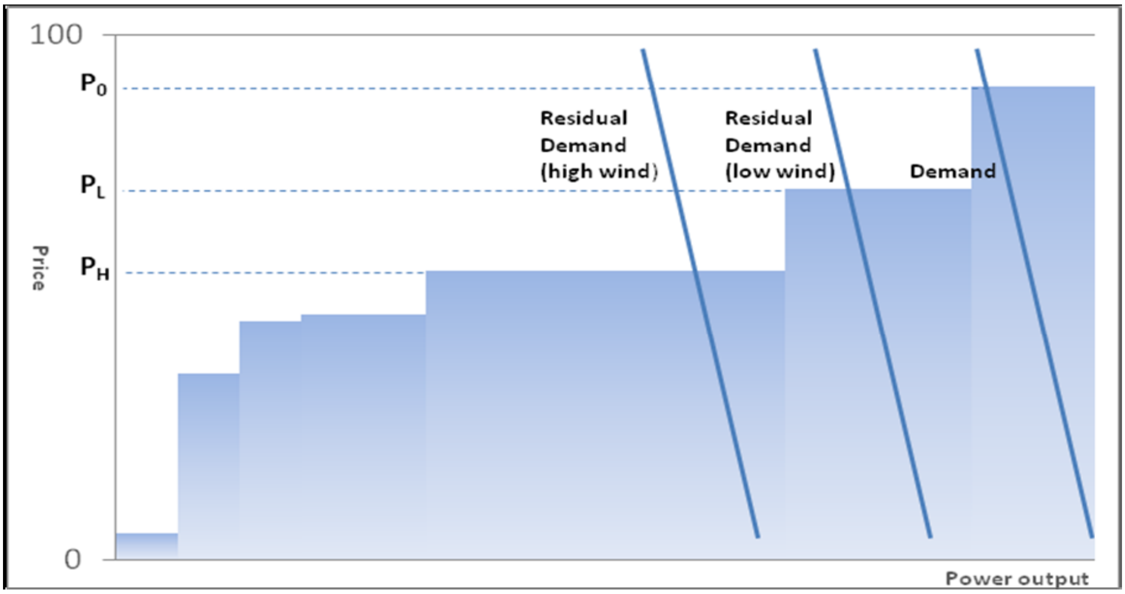


Figure 1 shows electricity supply in blocks of increasing marginal costs (e.g. nuclear plants to the far left and oil plants to the far right). Wind is characterised as negative demand since it generates at very low marginal costs and is therefore always dispatched.

During periods of very high wind (and low demand), where wind output exceeds demand, prices in the GB market could go negative since wind operators would still be willing to trade in the market so long as the price they 'pay' is less than the value of a Renewable Obligation Certificate. Similar conditions occur in other markets, since the Feed in Tariffs common in other countries also insulate wind generators from wholesale price movements. Indeed in many instances renewables are given priority access by system operators. Studies from overseas are therefore relevant to the British situation and numerous modelling and empirical studies have attempted to estimate the impact of renewables on electricity markets. These studies all conclude that wind will depress prices. For example:

- Sensfub et al (2008) use a simulation model to estimate the impact of renewables (mainly wind) on spot market prices in Germany. They estimate that a wind penetration of around 10% in 2006 (52 TWh) results in a reduction of average spot price of €7.83 / MWh (approximately 15%), compared to a counterfactual with no wind.
- A modelling study by the regulatory authorities in Ireland (CER and UREGW, 2009) looked at the effect of wind on wholesale prices under a range of scenarios with wind penetrations ranging from 16% to 42% and with different mixtures of conventional generation. For most of the scenarios prices were significantly depressed (by between 9 and 21%). However, the exception was a scenario which assumed a high proportion of Open Cycle Gas Turbines (OCGTs), where prices were 10% higher than the counterfactual.
- Moesgaard and Morthorst (2007) statistically analyse spot prices between 2004 and 2007 in Western Denmark and concluded that they were reduced by 5-15% as a result

of wind power. During this period the penetration of wind was approximately 20-25%. Neubarth et al (2006) conduct a statistical analysis of time-series data in Germany in 2004/5 when wind penetration was around 5%, concluding that wind power reduces the average daily spot market price by €1.89/MWh for every GW of average available wind energy. They estimate that the 18.4 GW of installed capacity resulted in an overall average price reduction of €6.08/MWh (approximately 12%).

In summary, these studies generally conclude that wind has a negative impact on average spot prices of the order of 1% for every 1% of additional wind penetration. Price effects may be more extreme under similar wind penetrations in GB because it has relatively low interconnection and hydropower capacity to balance fluctuations in wind output, compared to some of the countries studied above (DECC, 2009b). In the long term, where the make-up of the conventional generation mix can change more radically (through closures and new build), it is more difficult to predict the impact of wind on electricity prices. The lower load factors experienced by plants with relatively high capital costs (and low marginal costs) means they may be replaced by peaking plants with low capital cost and higher marginal costs, such as OCGTs (Nicolosi and Fursch, 2009; Saenz de Miera et al, 2008). This would push up average prices (see Figure 2).

Figure 2: The long-term impact of wind on electricity prices (Author's illustration)

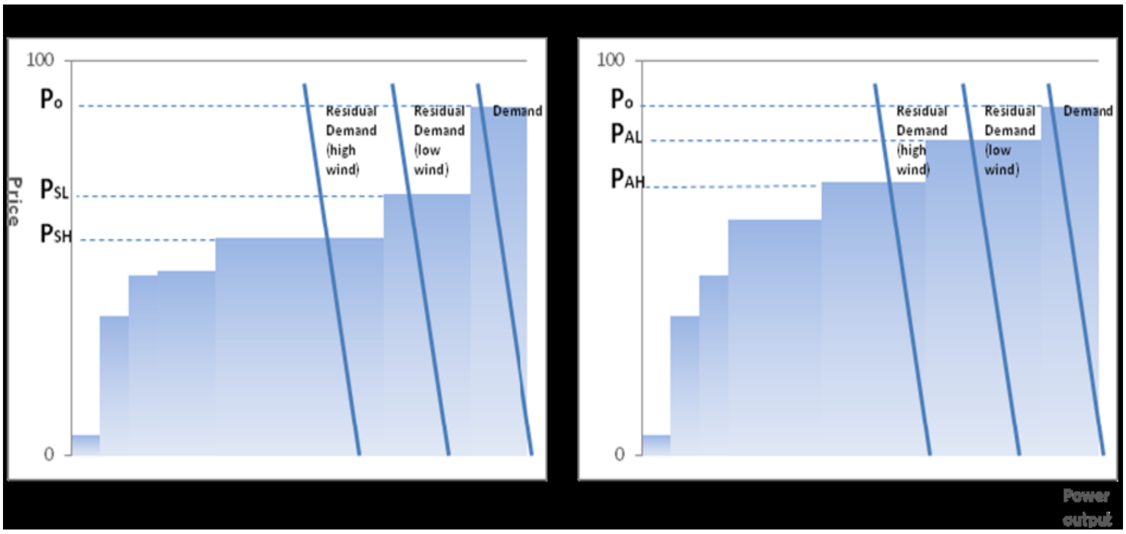


Figure 2 is an illustrative representation of equilibrium prices in two peak demand scenarios: (i) where the conventional generation mix order remains dominated by CCGTs and coal stations and (ii) where the conventional generation mix is adapted to a high wind penetration with higher proportion of higher marginal cost plants (such as OCGTs). Under a standard generation mix, the market clears at PSL and PSH under high and low wind conditions respectively. Under a 'wind-adapted' generation mix, the corresponding prices are higher, at PAL and PAH. In this way, the dynamics of the conventional generation mix as a response to wind could work to push up electricity prices in the long-term. This could partially offset or even exceed the 'displacement' effect of wind.

On this basis, electricity prices in the UK in 2020 under 30% wind are likely to be highly dependent on what plants are built to replace the coal, oil and nuclear plants which are retired in the next decade. Most analysts expect that it will be mainly CCGTs that are built this decade (Poyry, 2009, Redpoint, 2009) rather than OCGTs or new coal, and the authors' analysis supports this view, as we explain below. Therefore it appears unlikely that competitive spot prices will rise and they would most likely fall as wind capacity increases - all other things, such as fuel and carbon prices, being equal.

Impact of wind on spot price volatility and risk

Although geographical dispersion of wind farms can smooth variability in wind output, correlation in wind speeds across the GB and concentrations of sites in certain areas will mean that overall wind output will vary significantly over hours, days and month (Gross et al, 2006). This will in turn drive volatility in spot prices under high wind penetrations. Increased volatility will give rise to price spikes significantly above the costs of the marginal generating unit when demand is high and wind speeds low (Joskow, 2008; Redpoint, 2007). These 'price spikes' are likely to be higher under high wind penetrations, given that conventional plants will need to recover their capital costs over a smaller number of running hours (Poyry, 2009; Redpoint, 2009).

Modelling by Poyry (2009) shows that electricity prices could become extremely volatile by 2020 under 33 GW of wind. Modelled prices become negative during many periods (with wind output valued at minus 1 ROC) whilst there are also a few hours where prices almost exceed £1000/MWh (to put this in context, spot prices reached a high of £500/MWh last year (DECC, 2009b)). Crucially, the Poyry study found that the frequency of such price spikes was found to vary from year to year. As the report states, *"in a given year these prices spikes simply may not occur"* (Poyry, 2009, p.18). Modelling by Redpoint (2009) also show substantially increasing price volatility over the next two decades. By 2030 they estimate that prices will exceed £500/MWh for a few hours a year with negative prices occurring 1.3% of the time.

Assessing the interplay between potentially very high but highly uncertain price spikes, depressed average prices and investment decisions is far from straightforward. Viewed from the perspective of an individual company any investment decision is further complicated by the need to take account of the actions of competing companies, for example the financial feasibility of any ‘super peaking’ plants build to benefit from price spikes is predicated on them being in relatively short supply. However a simple representation of the relative attractiveness of different types of generating plant for different modes of utilisation can be provided by comparing levelised costs at different load factors. In what follows we review the relationship between utilisation, capital and operating costs and the need for flexible operation.

4. Investment incentives for different types of plant in a high wind electricity market

Flexible thermal plant

Wind power is estimated to have a capacity credit of around 10%-20% at a 30% wind penetration (Gross et al, 2006; National Grid, 2009b). Therefore, the overall capacity needed to provide the same level of reliability of meeting peak demand increases as the amount of wind capacity increases. Poyry (2009) estimate that by 2020 load factors would be around 55% for ‘new’ CCGT plants (down from a current load factor of over

70%), 50% for coal plants (down from over 55%) and less than 5% for 'old' CCGTs (down from over 25%) (Poyry core scenario with 33 GW wind). Similarly, Redpoint (2009) show the load factor of a 'representative' CCGT built in 2009 falling from over 80% to below 50% by 2020 in a scenario with 23 GW of renewables.

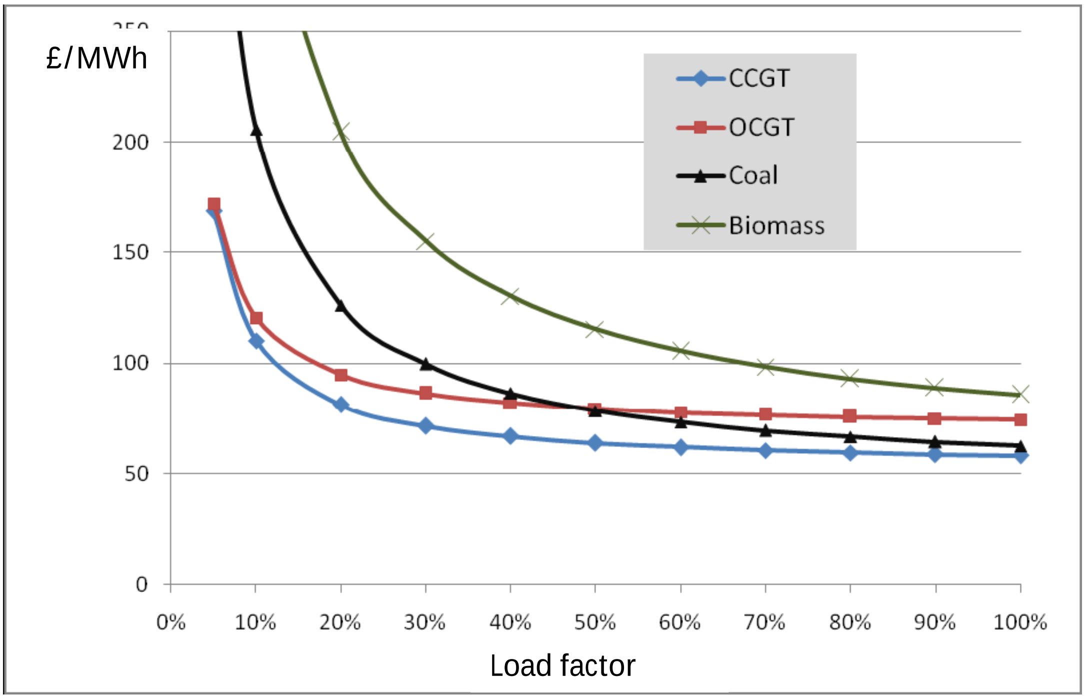
As explained above, with lower load factors and long periods of low prices, conventional plants are likely to rely more heavily on higher prices during periods of low wind to make them economically viable. However, due to the variability and unpredictability of wind output and the diurnal and seasonal variability of electricity demand, the price and usage patterns of conventional plants are likely to be unpredictable across days, months and years.

Poyry (2009) found that year on year wind output varied by a range of 25% in Britain between 2000 and 2007 which translates into similar variations in average load factors for conventional plants. Peaking plant, which are already exposed to load factor risk from demand variability, will be particularly exposed to significant load factor risk generated by volatility in wind output over hours, months, weeks and years. Depending on what wind output is at times of peak demand, 'super-peaking' plants can be used for a few hours one year, and not at all the next. This load factor risk creates a significant revenue risk for plant owners.

Increased wind penetrations will also affect the relative economics of different types of thermal plant. As discussed earlier, as load factors of conventional plants fall, the emphasis will increasingly be on building plants with lower capital costs with marginal costs becoming less important. This is because there will be fewer hours of operation during which revenue can be earned to 'payback' capital costs incurred. The higher revenue risks implied by high levels of wind is also likely to encourage lower capital cost plant types, since raising capital is likely to become more costly. Figure 3 shows how load factors affect the relative levelised costs of plants.

Figure 3: Levelised costs for conventional plants in 2020 under different load factors

(assuming a cost of capital of 10%)



Source: Authors' analysis using cost data from SKM (2008), see Annex 1 for assumptions

As the figure shows, when load factors fall below around 40 -50%, CCGTs and OCGTs, will be favoured as new investments over more capital intensive plants, such as coal power stations. Moreover, it is also reasonable to expect that flexibility will become an increasingly attractive characteristic as wind variability increases ramp rates and the uncertainty around the net demand for electricity. This is likely to increase revenues available from the balancing market for plants that are able to provide short term reserve (National Grid, 2009; Redpoint, 2009).

OCGTs are less capital-intensive and more flexible than CCGTs and are therefore likely to become a more attractive investment as wind capacity grows. However, the levelised cost assessment described above suggests that CCGTs remain the most viable investment for all load factors above 5% and therefore most new flexible plant investment is still likely to be CCGTs in the next decade. Whilst the representation above is highly sensitive to the relative prices of coal and gas, the analysis demonstrates that, other factors being equal, substantially increased wind power is likely to lead to an even greater focus on gas over coal in providing conventional capacity. In the absence of additional measures the viability of new coal is likely to depend on whether it can maintain load factors by having lower marginal costs than other conventional plants. This is likely to become increasingly difficult if the cost of carbon rises as expected and will be exacerbated by the higher marginal costs of carbon capture technology.

As well as affecting new investment, increased penetrations of wind will also influence the pattern of retirement of conventional plant. For the provision of peaking capacity, where load factors are low and risky, it is often more economic to extend the life of old plants (or bring them out of mothballs) than to invest in new capacity. The marginal costs of a plant tend to increase with age whilst capital costs will have been accounted for once amortisation is complete. Therefore, provided it is technically capable of doing so older plant may be well suited to provision of peaking capacity, when prices are high enough to cover marginal costs (Redpoint, 2006). If wind results in higher price spikes the economic case to extend plant life will be stronger. However since the Large Combustion Plants Directive will force the closure of many of the coal and oil fired plants that would otherwise have fulfilled this role the ‘natural’ process whereby older plants provide peaking capability will be restricted (Redpoint, 2009).

Finally, the higher electricity price risk under high levels of wind will favour plants which are both flexible and have other sources of revenue. Biomass plants have a major advantage as their electricity output is eligible for Renewable Obligation Certificates. Unlike electricity prices, ROC prices are not linked to real-time electricity market conditions and can therefore provide a relatively high and stable form of revenue.

Wind and other variable renewables

For variable renewables (which are generally dispatched when available) load factor risk is driven largely by weather patterns. High correlations in wind speeds across the UK can mean that as wind penetration increases it may increasingly start to 'cannibalise' its own economics, since high output will tend to correlate with lower electricity prices in the absence of enhanced supply side (e.g. storage and interconnectors) and demand side flexibility (e.g. real time pricing) to maintain wholesale prices during periods of high wind. Because wind and other variable reneweables are capital intensive, investment in these technologies is particularly sensitive to price risk (CCC, 2009; DECC, 2010; Gross et al, 2009). This is in contrast to fossil-fuelled power stations which have an inbuilt hedge against electricity price risk due to the (currently) strong link between electricity prices and fossil fuel prices (ibid). Wind generators will be partially insulated from this effect through the additional revenue available through ROCs and further insulated should the government press ahead with Feed in Tariffs or a Revenue Stabilisation Mechanism (DECC, 2009c; DECC, 2010).

Nuclear

New nuclear plants are expected to have similar levelised costs to conventional thermal plants (though build costs in Britain are as yet relatively uncertain), but its capital intensity creates a major challenge for investment (Gross et al, 2009; White, 2006). In a market with high penetrations of wind, with long periods of low prices and a short periods of high prices, nuclear will be at a disadvantage because of its high capital costs and relative inflexibility . Since nuclear is likely to run as baseload, its financial viability will be closely linked to average prices. Wind creates two sources of uncertainty in this respect. Firstly, the amount of new wind build is uncertain, and consequently the impact in lowering average prices is uncertain. Secondly, as the Poyry (2009) study showed, variability in wind speed distributions from year to year can generate variability in average annual prices. The long lead time for a new nuclear power stations (around 10 years) increases these risk exposures. For all these reasons, measures to help developers manage wholesale price risk could be important in bringing forward new nuclear. Related considerations may also change the optimal design of nuclear reactors, with those which allow even a small amount of flexibility likely to be of higher value in a high wind future (National Grid, 2009).

5. Market design, risk allocation and investment

In response to some of the issues described above, as well as wider issues in energy markets, the government and regulator have both published consultations which moot a range of changes to Britain's regulatory environment (DECC, 2010; Ofgem, 2010;). These measures range from market-based approaches aimed at improving price signals - such as enhancing the carbon price and sharpening price signals in the balancing market – to a number of more interventionist approaches which reduce exposure of generation plant to market signals and risks, and implying a more planned determination of investment decisions. These options envisage varying degrees to which low carbon generators might be provided with premium support, protected from wholesale price volatility or removed from the competitive element of electricity markets altogether. Some of the options also envisage changes which affect conventional generators, from various capacity payments/obligations to replacing competitive markets altogether with a single buyer (Ibid).

A thorough review of the full spectrum of possible changes to market design and regulation is beyond the scope of a single paper. In what follows we discuss some of the adjustments that are available to policymakers who wish to improve reliability and accelerate low carbon investment, exploring the limitations associated with each.

Allowing prices to spike?

Under high wind penetrations, where the load factors of conventional plants will be lower and more uncertain, price spikes during periods of low wind will very important in allowing plants to recover their capital costs. This will be particularly crucial for super-peaking plants which may only operate for a few hours in a given year (and sometimes not at all) and therefore require very high prices to make them economic. Since 'doing nothing' is a policy response in itself, the first issue to consider is whether simply allowing markets to work through volatile prices is an appropriate policy response. To the extent that policy-makers wish to encourage low carbon generation, a more effective system of carbon pricing could also be incorporated into this 'market driven' approach.

A key risk is that these price spikes may *not* be allowed to materialise. For example, problems in California in the early 2000s are often cited as a real-world instance in which regulatory intervention prevented prices feeding through into new investment. Intervention from governments and regulators to curb prices has been common in many countries. The Caliornia electricity crisis in 2000 - where rolling blackouts took place and many utilities fell into serious financial distress - is commonly attributed to the price restrictions which were implemented two years earlier (Rothwell and Gomez, 2003).

Under high wind penetrations, a winter of low wind could result in frequent price spikes and high average prices feeding through to consumers. This is could create strong political pressure to intervene. These interventions would be very damaging for investment in conventional plants, particularly peaking plants (Poyry, 2009). Even if these interventions do not materialise, the risk of political interference may be sufficient to deter investment (Helm, 2008).

Regulatory risk is (in theory) lessened by having a politically-independent energy market regulator, Ofgem, which has independent powers to regulate the electricity market in the interests of consumers. However, this has not totally resolved the problem of 'time-inconsistency' for two reasons. Firstly, politicians still have substantial powers to intervene in response to price spikes (for example, a windfall tax). Secondly, and more fundamentally, Ofgem has a legitimate role to intervene when market power is being abused but, as Roques et al (2005) note, it may be difficult to distinguish between this case and legitimate scarcity rents (such as those resulting from a period of low wind). Therefore, there is always the risk that Ofgem will intervene in error, when market power is not being abused. Moreover, many argue that the current rules in the balancing market mean that many balancing actions (e.g. voltage control) are not correctly priced and have the effect of suppressing balancing market prices well below the true 'scarcity' value (Newbury, 2005; Ofgem, 2010; Redpoint, 2009).

We have already seen that the year on year occurrence of price spikes is highly variable. In such conditions and with much old plant being forced to close, the economics and availability of peaking plants may be uncertain. The higher dependency on price spikes and the risks around these timing of these, coupled with continued regulatory risk, means active policy intervention may have a role in helping manage this risk. In what follows we consider the main options for such interventions.

Capacity mechanisms and capacity contracting

Capacity mechanisms are a potential intervention to help encourage capacity investment. They help mitigate load factor and price risk by providing a revenue stream additional to that from electricity sales. As a result, investment risk for capacity investment can be reduced and the market becomes less dependent on wholesale price spikes to bring forward investment (Joskow, 2008; Poyry, 2009; Roques et al, 2005;).

Common criticisms of capacity mechanisms (Roques et al, 2005; Green, 2008; Redpoint, 2009) are that (i) overall generation costs are increased by keeping underused (and often inappropriate) plant on the system; and (ii) by muting price spikes incentives to invest in demand side infrastructure can be dulled - although the demand side can participate in capacity mechanisms. Other drawbacks are more specific to the type of mechanism. For example, capacity obligations can be volatile and open to market power abuse due to inelastic supply of capacity in the short term (Bowring, 2008; Moran and Skinner, 2008). Capacity payments have high uncertainty of outcome and are reliant on the regulator setting the ‘right’ payment level (DECC, 2009b; Oren, 2000,).

Given these drawbacks, the case for a capacity mechanism is not clear. Any capacity mechanism would need to be tailored to the expected future generation mix. In a market with large amounts of inflexible plant (e.g. wind and nuclear), flexibility and fast response is likely to be more valuable (Poyry, 2009; Redpoint, 2009) and therefore any capacity mechanism would need to reward this. Many existing capacity mechanisms have been criticised for rewarding poorly maintained plants with low availability and slow response (Roques et al, 2005) although some mechanisms, such as that used in the PJM market in the Unites States, include performance incentives to avoid this (Chandley, 2008). Perhaps the main attraction of a capacity mechanism is the reduced reliance on price spikes to bring forward capacity. If prices spikes in a high wind future are deemed to be unacceptable or at high risk of political intervention, the case for a capacity mechanism will grow.

An alternative capacity mechanism is for the system operator to intervene by directly contracting for strategic reserve capacity of 'last resort' (DECC, 2009b) which would be used in the event that other options to balance the supply and demand fail. An example of this practice is the Nord Pool, where three of the System Operators hold 'strategic reserves' (Botterud and Doorman, 2008). The main concern with these mechanisms is that they may crowd out other investment by depressing prices. Thus, to ensure the capacity is genuinely additional, reserves must only be use in times of extreme shortage (e.g. when spot prices spike to a defined level) and the rules around when new capacity is contracted for and used need to be well-defined. However, if they are only used in extreme circumstances, their presence may impose an unnecessary cost. Thus, as with any intervention to secure extra capacity, the key question is whether the extra insurance over reliability is sufficient to justify extra costs to consumers.

Removing wholesale price risk for low carbon generation?

Under high penetrations of wind, and as price volatility increases, a major question arises as to what extent low carbon generation technologies should be exposed to wholesale price risks and utilisation risks. Many potential reforms aimed at encouraging the deployment of low carbon technologies have the effect of eliminating or reducing the exposure of technologies to wholesale price risks, such as Feed-in tariffs (FIT). This can help to substantially de-risk investments, reducing the cost of capital and encouraging investment and deployment (CCC, 2009; Gross et al, 2009; Klessman et al, 2008). In principle it is possible to extend fixed price schemes to all low carbon options, differentiated by technology as appropriate. Ofgem (2010) moot the possibility of doing so through a form of capacity obligation, with prices set through a system of auctions.

An important draw back with fixed price systems is that exposure to price signals (and risks) plays an important role in revealing the 'true value' of energy and in shaping efficient investment, dispatch and availability patterns. In particular, exposure to price movements ensures that:

i) Efficient dispatch and availability patterns are encouraged. If plants are not exposed to market price they may dispatch even when low, zero or negative prices are revealing that generation is of little value to the system, thus increasing the cost and difficulty of balancing the system and increasing risks (and costs) for the residual market (Abbad, 2009; Hiroux and Saguan, 2010). Under high wind penetrations, it will be important for large amounts of generation mix to be responsive to fluctuations in wind output. This may even include relatively inflexible plants such as nuclear and wind itself (National Grid, 2009). In addition, price risk exposure is important in encouraging plants to be available at times when the market is likely to be short (e.g. maintenance can be planned for periods of low demand and low prices ensuring that plant is available when it is most needed).

ii) A diverse generation mix is encouraged. Exposure to price signals rewards plants which are able to generate when electricity is scarce and prices high. Thus a flexible plant mix is encouraged where supply can be efficiently matched with demand. This will become increasingly important under high wind penetrations. Moreover, price risk exposure helps encourage generation diversity. For example, as wind penetrations increase and prices become depressed during windy periods, so the incentives to expand wind capacity will fall.

iii) Geographic diversity is rewarded. Price exposure creates an incentive for geographic dispersal of wind farms to locations where wind speeds are less correlated with other farms – since a wind farm will benefit from higher prices if it generates at times when overall wind output is lower (Hiroux and Saugan, 2010). In turn, this should help reduce the overall volatility of wind output and the corresponding impacts on the stability of the market.

For all these reasons, support mechanisms which *completely remove* technologies from price risk (such as feed-in tariffs) or distort wholesale price signals (such as any output-based subsidies) may be less desirable in the long-term, particularly if they cover a high proportion of the generation mix. However, given the size of the low carbon investment challenge, the increased risk of this investment and the recent re-pricing of risk in finance markets due to the banking crisis (DECC 2010), some mechanism to reduce investment risk may still be required. In this sense, intermediate solutions which remove some (but not) all of the risks around wholesale markets may be warranted.

As an example of this, DECC recently proposed a ‘revenue stabilisation mechanism’ where renewable generators would receive a contract for differences to remove risks around movement in *average* electricity prices (DECC, 2009c), which would include, as Newbury (2010) notes, the risks around the future carbon price. A key advantage of this approach is that renewables generators still trade in the market. They therefore have incentives to dispatch and locate efficiently. Such a mechanism could also be designed with ’caps and collars‘ where some, but not all, of average price risk is removed, allowing some market signals to be retained whilst removing exposure to some of the extreme ‘low-price’ outcomes which make financing difficult. Abbad (2009) discusses how Spanish renewables support has evolved from a pure FIT to a premium tariff option (which leaves plants exposed to wholesale prices), arguing this has been crucial in encouraging efficient dispatch patterns as well as the technologies needed to allow efficient management of balancing risk (such as controllable turbines and better wind forecasting tools).

Another possible response to the ‘efficient dispatch’ problems identified above is to return to a form of planned dispatch for low carbon generation. Rather than exposing low marginal cost generators to a modicum of market price, this model returns to a coordinated least cost dispatch model developed for monopoly ownership and operation (and retained to some extent under the former England and Wales pool). The key question here is whether a central planner could co-ordinate dispatch patterns more efficiently than market players incentivised by market signals in the wholesale and balancing markets.

As the share of low or zero marginal cost plant expands the *residual* market for fossil fuel plants will become smaller. Hence, *at some point* it can be argued that the very basis on which current markets are constructed, which is to optimise the utilisation of fuel burning plants, begins to be undermined. For as long as fossil fuel plants continue to occupy a significant share of generation this point is some way off, but it is important to note that a system that seeks to match the output of a large system of near zero marginal cost generators to demand could require very different characteristics.

Allowing the market to function better through increased demand-side flexibility

As stated earlier, some of the problems which liberalized markets face in delivering sufficient investment stem from a lack of demand side engagement in the market (Joskow, 2008). In Britain most domestic consumers are not exposed to real-time pricing, nor can they enter into interruptible contracts because the communications infrastructure needed to facilitate this (e.g. smart meters) is not in place.

More responsive demand could allow ‘peak-shaving’ at times of low wind and high demand, reducing the number of units with low capacity factors needed to ensure supply and demand balance (Adib et al, 2009). This would reduce the overall system margin needed to deliver a given level of reliability. Moreover, more elastic demand for electricity will help to smooth prices, reducing price risks and encouraging investment. For these reasons, measures to encourage and facilitate demand side engagement, such as mandated role-out of smart meters (DECC, 2009a; Ofgem, 2010) could be highly valuable in developing a better functioning market, suitable for high penetrations of wind power.

6. Conclusion

As the electricity mix decarbonises, large amounts of variable wind power on the system will increase market risks for conventional generators, which is likely to discourage investment in generation capacity. None of the options to address the higher risks associated with high wind scenarios are without problems and (with the exception of improved demand side response) it appears essential that policymakers make an effective trade off between reducing investment risk whilst retaining the efficiency benefits of market signals.

Market risks play a fundamental role in shaping efficient investment and dispatch patterns in a liberalised market. For this reason, measures to improve price signals and market functioning (such as a more robust carbon price and developing a more responsive demand side) have considerable merits. However, the sheer scale of the investment challenge and the increased risk of this investment mean that targeted measures to reduce (although not eliminate) risk, such as capacity mechanisms and fixed price schemes, may be increasingly appropriate. All policies options have advantages and problems. Moreover, the more interventionist policy becomes in terms of low carbon the more difficult it becomes to maintain a role for markets in any ‘residual’ sector. A key challenge for policy will therefore be to strike a balance between enhanced market response and planned capacity addition. This balance may not be easy to achieve and policymakers may face a more fundamental choice between planning and markets than some commentators yet recognise.

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Annex 1: Cost data for Figure 3

Plant Type	**Capital Costs** (£/kW)	**Fixed Operating Costs** (£/kW/year)	**Marginal Costs** (£/MWh)
Gas (CCGT)	**440**	**7**	**52.1**
Gas (OGCT)	**270**	**18**	**69.1**
Coal	**1050**	**34.5**	**46.6**

Biomass	**1600**	**100**	**56**

Source: SKM (2008)