Electricity Market Evolution under Deep Decarbonisation

W.J. Blyth, D.W. Bunn, and M. Chronopoulos

EXECUTIVE SUMMARY

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There is growing recognition that a transition towards low-carbon generation sources will also require a transition in the policy and regulatory frameworks in which electricity markets operate. Market-based approaches to electricity decarbonisation rely upon incentives. Their effectiveness is therefore as much a function of behaviour as it is of fundamental economics.

This report addresses two key issues that affect investment in the context of a decarbonising power sector. The first relates to behavioural responses to risk and uncertainty. We investigate the degree to which revenues need to be raised in order to overcome risk premia that companies apply in the face of risky market price signals, induced by the technology changes and policy initiatives, and how these risk premia change over time during the process of decarbonisation.

This extra revenue requirement raises the question of how it may be achievable. We discuss policy support as well as the market forces that may support higher wholesale prices. We observe that as the markets become more risky, we would expect them to become more concentrated and thus we investigate the extent to which companies operating in imperfect markets are able to achieve these extra risk premia by using some degree of market power. It is well recognised that companies even in relatively competitive electricity markets often have the capacity to manipulate prices to some extent. We investigate here some of the key sensitivities and drivers of this market power in order to understand how this might change as the structure of the power sector changes during the decarbonisation transition process.

The second key issue relates to policy intervention and in particular whether a carbon market can be sufficient to achieve decarbonisation goals, recognising that market participants are risk averse and may not behave simply according to economic signals. Because of behavioural reactions, we show that carbon market signals may not translate into as much early investment as expected, yet if the system is allowed to work, this should be corrected later (but with some welfare loss). We suggest that if policy-makers do not have the patience and trust in the carbon market to work through this friction in investment signalling, and instead introduce extra stimuli, these may erode the carbon prices signals further and introduce extra policy risk to the market participants.

To inform these issues, we present the results of a model based on a representation of the Great Britain (GB) electricity market that is stylised so as to be able to draw generalizable conclusions. The model has three distinct components, which run in an iterative way to understand different aspects of the decarbonisation process. The first component is a long-term least-cost capacity planning model used to assess the impacts of long-term risk and uncertainty. This provides endogenous calculation of carbon prices, and assesses how market structure and generation mix expectations evolve over a 30 year period in response stochastic variation in inputs (notably fuel prices and technology costs & constraints).

The second component is a short-term price risk model which provides hourly dispatch and pricing outputs given a particular set of assumptions about the mix of generation plant available. This can be used to look at the detailed response of the electricity market to increased penetration of intermittent renewable sources, taking account of short-term fluctuations in input fuel prices, as well as fluctuations in hourly demand and wind availability.

The third modelling component is an agent-based model which uses a computational learning algorithm to derive pricing behaviour in imperfect markets. We explore the capabilities that companies may have, under alternative market structure assumptions, to offer capacities and prices to the wholesale market, in a way that acquires the higher required revenues to support new investment. In the model, market participants learn to maximise their daily operational profit contributions of all plant in their portfolio, where such operational profits are defined from the market clearing prices, the marginal costs and the hours of operation of each plant.

The results of this work indicate that the risk characteristics of electricity markets will be substantially altered as a result of decarbonisation. This in turn substantially alters the propensity of companies to invest, and has significant implications for policy, both in terms of the design of electricity markets, and also in the way in which low carbon investment is supported. Key conclusions are as follows.

Current carbon cap in the EU-ETS is insufficient to drive significant decarbonisation over 35 years

The results here confirm other's findings that the current EU-ETS rate of decarbonisation is insufficient to meet estimated emission targets for the EU of 80% reductions or more by 2050, and even further out of line with estimates that the electricity sector will need to decarbonise more rapidly than the rest of the economy[1]. Prices in the EU-ETS are currently low (below €6/tCO_2), but not zero. This is in line with model results that some level of banking against future scarcity can raise prices even when the market is over-supplied.

In order to understand the effect of decarbonisation on market operation, the research in this paper explores scenarios with significantly greater rates of decarbonisation than currently envisaged in the EU-ETS.

By itself, the increasing penetration of intermittent renewables reduces the attractiveness of investment for all technologies in an energy-only market

Taking a snapshot in time of the generation mix, and keeping all else equal, an increasing penetration of intermittent renewables (modelled here as onshore and offshore wind power) will tend to increase price risk and reduce average expected prices in electricity markets. In the GB context, with up to about 30GW installed capacity of wind (which would replace about half of the ~ 20GW of coal in the system), the risk profile of electricity prices does not change very much. Above this level, however, price risk increases significantly with each new GW of wind installed in the system as the probability of demand being met by very low marginal cost plant starts to increase, reducing overall system prices. If all 20GW of coal were to be replaced (by 60 GW of wind), there is a substantial chance of daily average prices falling to zero or becoming negative. The probability distribution of prices in winter peak hours is likely to become more complex, with multi-modal

[1] E.g. UK Committee on Climate Change

distributions indicating regime-switching in price-setting, creating the need for more sophisticated risk management models for peak hours. The simple replacement of coal with wind based on maintaining its average annual availability will also tend to erode system reliability, and increasing potential outages unless additional flexible capacity is added to the system to compensate for short-term fluctuations.

Whilst this kind of static technology replacement analysis is clearly an oversimplification of the actual development pathways for the power sector, it nevertheless demonstrates a real downward pressure on average prices and an increase in price volatility which leads to an erosion of the profitability of all potential new investments. Policy support mechanisms (e.g. subsidies) for low-carbon generation sources will need to take account of this feedback mechanism: the strong conclusion is that it will not be sufficient for subsidies to simply decline in line with capital costs as volumes of renewables increases.

Uncertainty and imperfect foresight alters price trajectories and price risk in carbon markets

The analysis suggests that behavioural factors can have an important effect on carbon price trajectories in a cap-and-trade scheme. Under assumptions of perfect carbon markets with unlimited banking of allowances, economic agents and perfect foresight, carbon prices tend to be set in the relatively long-term when carbon constraints are at their most economically demanding. Discounting this economic signal back to current values creates a smooth carbon price trajectory over time. With perfect foresight, short-run prices can be supported by this need for long-run decarbonisation even in an over-supplied carbon market.

Under imperfect market conditions, uncertainty over the level of future carbon caps creates uncertainty over the amount of allowances that should be banked. This creates a substantial margin of error in carbon prices in the short term (5-year time frame). Whilst a carbon cap scenario consistent with 30% decline in emissions by 2020[2] in the EU-ETS would indicate an optimal near-term carbon price of \$25/tCO_2, sub-optimal banking of allowances would put carbon prices anywhere in the range \$10–30/tCO_2. Carbon prices under the current less tightly constrained carbon cap are correspondingly lower.

The results show that assumptions of optimal banking will also tend to substantially underestimate carbon price variability in the medium-term (5-15 year time frame) under stochastic conditions when compared to assumptions of imperfect banking. For the range of stochastic variable inputs used in this modelling work, the standard deviation of carbon price variations approximately doubles (from about 10% to about 20%) if banking of allowances between periods is no longer allowed. This illustrates the importance of taking into account behavioural factors in markets which operate under conditions of uncertainty.

'Price vs. Quantity' revisited: unreliable taxes vs. unreliable caps

The analysis suggests that considerations of policy risk could potentially reverse previous conclusions about the effectiveness of taxes vs. cap-and-trade instruments. It is a well-established result of

[2] In this analysis, the central carbon cap scenario corresponds to a rate of decline of the carbon cap of 3.5% per annum. This is faster than the current rate in the EU-ETS (1.74%). The central cap scenario corresponds roughly to the 30% reduction target by 2020 that was once proposed for a tightened EU cap.

environmental economics that price instruments (i.e. taxes) would tend to perform better than quantity instruments (cap-and-trade) under conditions of uncertainty for environmental problems such as climate change. However, that result is derived assuming that the policies themselves are certain. This study indicates that if the policies are unreliable, then the opposite may be true. If future tax rates are unreliable, they may be subject to greater discounting by current decision-makers. Whilst taxes in the short-term could stimulate reversible abatement options such as fuel switching from existing coal to gas plant, the greater discount rate would means that long-run prices would fail to translate into expectations of future change, and would therefore fail to bring forward investments in new low-carbon generation. An unreliable tax may therefore have very little environmental impact.

Unreliable carbon caps on the other hand may lead to low price signals in the short-term if agents in the market apply a higher discount rate to the carbon price trajectory. This would fail to bring about short-run abatement options such as fuel switching, making unreliable caps less effective than unreliable taxes in the short-term. However, as long as market agents believe that caps will ultimately be enforced (even if the level of the caps are uncertain) then the lack of abatement in the short-term feeds back into an increased long-term expectation price of carbon. This feedback, which is absent in the case of a tax, leads to greater impetus for change in the medium- to long-term than an unreliable tax. Clearly, if agents do not believe that a cap will ultimately be enforced, then this relative advantage of caps would be lost.

Low carbon technologies have a greater financial exposure to long-term uncertainty than gas or coal plant

In a market where power generators derive their income solely from the sale of electricity, where all generators receive the same price at the time they are generating, and where this price is determined by the marginal cost of generation, it follows that all generation technologies will be exposed to risks associated with uncertainty over the long-term values of these generation costs.

However, within this perspective of market fundamentals, the degree of exposure varies considerably for different generation types. This analysis developed here uses real options analysis to quantify these risks. Our approach compares revenues required for an investment to break-even under uncertain future outcomes (balancing positive and negative outcomes) with a delayed investment strategy that could avoid some of the negative outcomes, whilst foregoing income during the period of the delay. The analysis suggests that low-carbon technologies tend to be more exposed to some key sources of uncertainty than traditional fossil-fuel generation sources. These sources of long-term uncertainty include the capital costs of new plant, future fuel prices, the level of carbon emissions caps, and the capacity factor associated with wind generation. The total exposure to long-run risks was lowest for CCGT. This is because gas plant is most often setting the system marginal cost, and therefore retains the closest correlation between generation costs and revenues. The degree of extra mark-up required to compensate investors for taking on these long-run risks appears to be low (<10% above breakeven revenue levels). Coal plant has the next lowest risk exposure, requiring mark-ups above breakeven prices of between 10-20%. Carbon capture and storage (CCS), nuclear and wind all have considerably higher risk factors. Prices would need to be between 30-60% higher than the risk-free breakeven price in order to overcome the risk premium.

For nuclear power, the sources of risk are approximately evenly distributed between capital cost risk, fuel price risk (mainly exposure to gas price uncertainty), and uncertainty over the level of the carbon cap. Wind power has less exposure to capital cost uncertainty, but more exposure to fuel price risk, whilst CCS tends to be more heavily exposed to carbon cap risk. Biomass + CCS is exposed to additional fuel price risk because of the uncertainty over feedstock prices.

This suggests that low carbon generation sources face investment hurdles not only related to their expected costs, but also in relation to their risk premia compared to fossil-fired plant. Clearly, as more policy interventions are introduced, the economic analysis moves more away from market fundamentals, and this picture changes, but these interventions bring extra policy and regulatory risks in exchange.

Electricity price risk pushes back the timescale over which low-carbon generation becomes cost-competitive

Short-term fluctuations in electricity prices arise as a result of short-run fluctuations in fuel prices, demand and plant output. Whilst such variations may average out over long time periods, investors and companies are averse to financial underperformance on an annual basis.. The risk of such exposure would therefore be incorporated into financial planning of the investment. This short-term risk is modelled here by quantifying the additional revenue (or mark-up in prices above system short-run marginal cost) required in order that net profit should not only exceed capital repayment costs, but should exceed them by a factor of 1.2 with at least 95% probability, in line with the level of metrics often used by lenders and ratings agencies.

These short-run price risks vary considerably between technologies. For gas plant, these risks are considerably reduced because they tend to set the system marginal cost. For coal plant, as carbon caps become increasingly tight over time, the risks increase substantially over the medium term to long term. For example, under an EU carbon cap pathway consistent with a 75% reduction in emissions between 2010 and 2050, coal becomes priced out of the market after around 15 years, and gas after around 25 years.

Low carbon technologies on the other hand would be expected to become increasingly cost-effective in this modelling as a result of increasing fossil fuel prices and tightening carbon caps. The lowest-cost form of low-carbon generation (in this analysis, nuclear) would under the assumptions of this modelling already be competitive with gas-fired plant in a risk-free world. However, including the effects of risk in the investment analysis pushes back the date at which this competitive level is reached by around 10 years. The timescale over which other low-carbon technologies reach cost-effectiveness (in comparison with gas) are pushed back by a similar amount of time. This suggests that policy support mechanisms for low-carbon technologies may have to remain in place for longer than would be anticipated under a risk-free analysis.

The combination of long-run and short-run risk factors means that price signals in an energy-only market would be inadequate to stimulate new investment in the near term. However, the system would tend to correct itself in the medium term.

With the exception of gas-fired plant, the combination of long-run uncertainty and short-run price risks creates a significant additional hurdle for investment in new generation plant. This suggests that in the absence of any additional interventions or mechanisms for increasing revenue, investment signals may be inadequate in the short-term to encourage investment in new plant.

As well as quantifying the extent of these additional hurdles, this study follows through to look at the wider consequences for the development of the power generation system as a whole. The analysis shows that if an investment hiatus were allowed to develop as a result of these inadequate short-term market signals, and if this lack of new investment were to be compensated for by an extension in the lifetime of existing fossil-fired plant, then the system would tend to be self-correcting in the medium term due to two main mechanisms. Firstly, a hiatus would lead to an increase in emissions in the short-term (compared to the optimal decarbonisation pathway), which in the presence of enforced carbon caps would lead to an increase in carbon prices over the short- to medium-term. This tends to accelerate the improvement in investment conditions for all plant due to the pass through of additional costs towards a higher electricity price. Secondly, this feedback mechanism also tends to reduce both the long-run and short-run investment risks for all plant (except for unabated coal plant). This again acts to bring forward the date at which the market would adjust to provide adequate signals to attract new investment.

The analysis therefore supports the view that energy-only markets with enforced carbon caps would not only eventually adjust to provide adequate levels of investment, but that this adjustment process would actually be faster (taking into account the reduction in risk) than would be suggested by an analysis that included risk in a static way (e.g. based on fixed discount rates).

However, this conclusion requires several caveats. The duration of the hiatus could be lengthy (10 years or more in our GB case study). Firstly, whilst the cumulative carbon emissions would be unaffected by such a hiatus, other environmental impacts which have not been taken into account in this analysis would likely increase. Secondly, the assumption that existing fossil plant could simply be extended is simplistic (no account has been taken for example of the EU Large Combustion Plant Directive which puts a limit on the future operational hours of all but the cleanest of oil and coal plant). However, were the hiatus to incur lower reserve margins, prices would increase and provide a compensating stimulus for investment. Thirdly, this analysis does not take into account that such a hiatus would interrupt the development of supply chains and the economies-of-scale required to achieve the technological learning for low carbon technologies that is incorporated into the cost assumptions.

Large companies may be able to mark-up prices sufficiently to make investment attractive, but such exercise of market power is very sensitive to conditions in the market

The agent-based modelling carried out in this study suggests that under certain conditions, companies will be able to exert considerable control over wholesale electricity prices even when markets are not particularly concentrated. That such behaviour is possible is confirmed by experience in the UK market in the period 2005 to 2008, a period when the [3]market concentration was well below conventional metrics, but when companies were nevertheless able to adjust available capacity in response to demand variations in a way that could help to sustain prices.

[3] Herfindahl-Hirshman Index (HHI) was less than 1000

The modelling in this study assumes that the market is dominated by a number of large companies, but that there is a competitive 'fringe' which act as price-takers in the market. The ability of the larger companies to manipulate prices is shown to be more dependent on the size of this competitive fringe and the overall amount of spare capacity in the system than on the number of large companies in the market. In an over-supplied market such as we have seen in the UK since the drop in demand after 2008, it becomes harder for companies to coordinate prices (even in a very concentrated market) without having to accept very large reductions in utilisation levels. Larger companies are more able to accommodate themselves to lower utilisation levels to sustain prices, and this would be a further reason to see increased consolidation in a decarbonising power market, especially if it must progress through a period of overcapacity.

In a market with a tighter balance between supply and demand, and / or a smaller share of the market supplied by the competitive fringe, large companies would evidently have greater potential to increase prices. This ability to control prices is linked particularly to the ownership patterns for fossil-fired plant, since these tend to the price-setting marginal plant on the system. This feature can give rise to a non-monotonic pricing property as decarbonisation progresses, with the ability to exercise market power varying according to the ownership and costs of the marginal technologies.

Thus, the ability to exert market power is shown to evolve over time in response to the evolving power generation mix as decarbonisation progresses. It appears that companies are able to exert price increases more readily under a tight carbon emissions cap scenario because of the earlier reduction in the capacity of coal and gas plant on the system. Likewise, policy scenarios in which renewable energy sources are forced into the system early (such as with the EU's 20% by 2020 targets) tend to increase the ability of large companies to exert market power, again by reducing the volume of gas and coal plant on the system compared to a base scenario.

However, whilst wholesale price manipulation has historically been an important part of market behaviour, and will presumably continue to be in the future, it is difficult to incorporate such considerations into projections about the attractiveness of future investment. Firstly, the ability to manipulate prices seems to be very sensitive to market conditions and to changes in the generation mix, and any company relying on this for their financial stability could be significantly at risk. Secondly, governments and regulators will tend to be intolerant of significant levels of price manipulation, so the upside potential will be capped. Thirdly, whilst some degree of wholesale price manipulation seems quite likely to play a role in the economics of plant already established in the system, it seems unlikely that companies could rely on it to underpin their investment case to raise finances for new investment.

Methodological Implications

Studies of alternative market designs and/or policy interventions are often (a) static in the sense that price formation for a future target year under a different pricing regime is simulated, (b) based upon assuming a perfectly competitive market, (c) that market participants are risk neutral, (d) that investment will occur if the NPVs are positive and (e) that carbon prices will follow an exogenous path to meet long-term targets. We have relaxed all of these assumptions.

Large-scale, long term least-cost capacity planning models have an important role to play in informing policy and are likely to be the baseline for investor views over the lifetime of prospective assets. But detailed consideration of how individual investment decisions will be made with risk averse considerations needs to overlay these insights to fully understand the propensity of investors to delay, or to require higher premia in order to act sooner. These effects on the model-based indications appear to be substantial, and can be developed in a transparent way through extra considerations of real options and risk analysis, as well as related strategic modelling.

Policy Implications

Current thinking amongst policy-makers is that the process of decarbonisation will require greater levels of policy intervention to support the levels and types of investment deemed necessary to meet climate policy and energy security objectives.

The analysis in this report only partially supports this view. It is shown that for an energy-only wholesale electricity market with firm carbon caps, whilst investment signals may be inadequate in the short-term, the market would adjust to provide adequate investment conditions over time.

Moreover, the inclusion of risk in the analysis indicates that the rate of adjustment may, surprisingly, be faster than otherwise expected. Furthermore, it is argued that market concentration in the power sector is likely to increase and that markets with even moderate levels of ownership concentration are quite often able to support prices sufficiently above short-run marginal cost to enable investment to proceed. However, these results are sensitive to market conditions, and the ability of companies to manage prices changes along the decarbonisation pathway.

However, tolerating either of these processes of investment are politically awkward. An investment hiatus would lead to higher emissions in the short-term, putting pressure on the enforcement of sufficiently tight caps in the longer-term. Furthermore, if a large part of the carbon reduction initiatives in the developed world are to lead by example climate mitigation in the more crucial developing world, the appearance of tolerating a go-slow process initially would be politically hard to sustain. The lack of investment in low-carbon technologies would also tend to undermine learning-by-doing, supply chain development and economies of scale. Explicitly relying on large companies to be able to support investments by exerting market power is potentially unattractive in a political environment committed to market liberalisation and reducing consumer bills, and a regulatory focus on reducing market price manipulation. Implicitly, however, a form of industry-institutional collusion may emerge in some countries where this has been more normal, with large, market dominant, companies working with governments to achieve targets.

In the absence of a toleration for market forces, meeting decarbonisation targets seems to lead inevitably down the route of greater levels of policy intervention. Including risk in the analysis suggests investment conditions vary significantly between technologies throughout the decarbonisation process, and the presence of strong feedback mechanisms between investment risk and low-carbon technology penetration. This implies that policy support mechanisms will also need to be more closely tailored to individual technologies, and careful monitoring of market conditions to achieve appropriate remuneration levels. This implies a greater level of regulatory intervention (and consequently a more fragmented market) continuing over longer time periods than expected in a risk-free analysis.

Table of Contents