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Structural and Behavioural Foundations
of Competitive Electricity Prices

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ABSTRACT
This chapter provides an introductory background to the fundamental and strategic drivers of price formation in electricity markets. It does not go into detail on the various time-series and econometric models, which are beginning to be applied to electricity data, as a range of these are presented in later chapters. Alternatively, it seeks to provide a basic understanding of why electricity prices are quite different in their behaviour and properties to those in other financial and commodity markets. It is also an introduction to some aspects of power system economics and electricity market liberalisation, for readers coming to electricity with experience of modelling other financial markets.

1.1 INTRODUCTION
From a financial and commodity markets perspective, wholesale electricity prices can generally be viewed as the result of investors having created real options upon various underlying primary fuel commodities such as gas, oil or coal. Although a substantial amount of electricity is generated from hydro and nuclear sources in various parts of the world, the dominant production process is still the thermal conversion of fossil fuels such as gas, oil and coal. This is a very capital intensive process, with surprisingly few workers actually being employed at the power plants. Thus, as electricity is often traded on exchanges close to an hour before it is needed, in this short term, the variable cost of power generation is essentially just the cost of the fuel. Even in power systems with a substantial amount of hydro and nuclear, it is the fossil fuel plant that often sets the market prices.

Depending upon the age and technology of the generating plant, in general, around a half of the energy content of the primary fuel gets converted into electricity. It follows from this, that with knowledge of the spot and futures market prices for primary fuels, and relatively well-known efficiency ratings for individual power plants on the system, the short-run marginal cost of each power plant on the system can be reasonably well estimated as a simple conversion of the fuel price. Of course, the owners of power plants would also like to recover their overheads and produce a return on investment, and so the spread between the market prices for fuel and power, the so-called tolling margin, is the value of owning and operating a power plant. As a real asset, or a contract held by a trader, the tolling margin represents the optionality of converting fuel prices into power prices. From this perspective, the
fundamental drivers of power prices should, it seems at first sight, be quite straightforward to understand.

In practice, however, whilst this fundamental concept is valid, its application has many complications. Take the case of gas, for example. This is now becoming the fuel of choice for electricity generation. The investment costs are lower than coal, or oil plant; it is cleaner and, depending upon location, the fuel costs are comparable. But with more and more of the gas resources being used for power generation, in some markets the issue of whether gas drives power prices, or vice versa, is not easily answered. Clearly, with convergence between two markets, they become partially co-determined. Figure 1.1 shows the daily average spot prices in the UK for gas and electricity. Clearly convergence was beginning to happen over this period, but at times, the relationship between the two is rather erratic.

Intuitively, the first reason that comes to mind, for the lack of an apparently better convergence with gas, is that gas may not be the only fuel source influencing prices. At some times it may be coal, oil or other plant that is dominant in setting the market prices. Just as the so-called “spark spread” refers to the spread between power and gas prices, the “dark spread” refers to the power–coal market price. As far as the British market has been concerned, gas has steadily been replacing coal as the dominant fuel since the mid-1990s, and there is evidence even in the few years shown in Figure 1.1 that the convergence with gas is improving. However, that is only part of the story.

Looking at Figure 1.1, the basic nature of the electricity time series does seem to be quite different to gas, even though there is a trend to an underlying convergence. As a time series, it is much more spiky, shows higher volatility and a stronger mean-reverting pattern. These, indeed, are the general stochastic characteristics of power prices, as observed in most markets around the world, and there is a fundamental structural reason for this.

The crucial feature of price formation in electricity spot markets is the instantaneous nature of the product. The physical laws that determine the delivery of power across a transmission grid require a synchronised energy balance between the injection of power at generating points
and the offtake at demand points (plus some allowance for transmission losses). Across the grid, production and consumption are perfectly synchronised, without any capability for storage. If the two get out of balance, even for a moment, the frequency and voltage of the power fluctuates. Furthermore, end-users treat this product as a service at their convenience. When we go to switch on a light, we do not re-contract with a supplier for the extra energy before doing so. We just do it, and there is a tendency for millions of other people to do likewise whenever they feel like it. Electricity may be produced as a commodity, but it is consumed as a service. The task of the grid operator, therefore, is to be continuously monitoring the demand process and to call on those generators who have the technical capability and the capacity to respond quickly to the fluctuations in demand. Figure 1.2 shows the annual range of daily demand profiles from England and Wales. Through a mixture of good forecasting and scheduling by the grid operator, together with a sufficient stock of flexible generating capacity, instantaneous production also follows these demand profiles.

Most spot markets for electricity are defined on hourly intervals (although the British market is half-hourly), and therefore it is clear that throughout the day and throughout the year, a wide variety of plant will be in action and therefore setting the prices at different times. Furthermore, we would expect a diversity of plant on the system for at least two reasons. The obvious one is obsolescence. With power plant lasting for some 40 years, new technologies will come in and be more efficient. So prices will be fluctuating because of the varying efficiencies of the set of plant being used for generation at any particular moment in time.

The more subtle, and second, reason for diversity is, however, again due to the instantaneous nature of the product. The most efficient plant, with the lowest marginal costs (the “baseload” plant), will operate most of the time, but during some of the peaks in demand, some of the power plants (the “peaking” plant) may only be operating for a few hours. The recovery of capital costs on peaking plant, through market prices, may have to be achieved over a relatively few hours of operation compared to the 8760 hours in a normal year for which a baseload plant,
without maintenance breaks, could, in principle, serve. Indeed, if we were optimising our stock of power plant, we would invest in some capital-intensive, low-operating-cost plants to serve the baseload, and some relatively cheap to build, but relatively expensive to run, plant (e.g. small diesel generators) available for the peaks. This is, of course, what does happen in practice, with the consequence that prices are much higher in the peaks. We will go through, in more detail, some of the basic economic aspects of the capacity mix in the next section.

So, whilst the fundamental nature of fuel price convergence has a mean-reverting implication, the instantaneous production process of following a highly variable demand profile, with a diversity of plant costs, creates the high spot price volatility. Other factors also come into play in the short term. There may be technical failures with plant, causing more expensive standby generators to come online. The transmission system may become congested so that rather expensive, but locally necessary plant gets called upon. And, of course, there may be unexpected fluctuations in demand. All of these events show up in spot prices. Average forward prices, would, in contrast, be expected to be rather more attenuated than the spot prices. Figure 1.3 shows average month-ahead prices, and compared with Figure 1.1, the fundamental convergence with gas is indeed rather more stable.

There is one further important characteristic of electricity markets, with major implications for price behaviour, and that is their imperfect nature. Most power markets are characterised by a few dominant players, and even in those less common situations where there may appear to be sufficient competitors to achieve efficient prices, at particular times and in special locations, individual companies may have the ability to influence prices. Of the academic research on liberalised electricity markets, by far the bulk of work that has been published has been done on the analysis of, and strategies for the mitigation of, the abuse of market power by the generating
companies. As a result of the presence of this market power, prices are generally much higher, and even more volatile, than the fundamentals suggest. In the third section of this chapter, we look at the strategic consequences on prices of imperfect market designs.

1.2 MARKET FUNDAMENTALS

An electricity system essentially provides capacity for immediate consumption, and we, as users, have acquired a call option, to exercise at our convenience, essentially unconstrained in volume up to the limit of our fuse-box. The total utilisation of this capacity by all customers on the system is referred to as the “load”, and the basic unit of load is the “watt”.

Terminology and Calibration

As an aside, a typical bright domestic light bulb may use 100 W. A thousand watts is a kilowatt, and a typical domestic electric heating appliance may use 2 kW. A small commercial building may use 100 kW. A thousand kilowatts is a megawatt, and a small gas or diesel generating plant (rather like an aero-engine) would generate about 50 MW. Another thousand megawatts is a gigawatt, and some very large power stations may be 2 GW. Energy consumption is generally integrated over time and sold to retail customers in kilowatt-hours (kWh). Wholesale power prices, on the other hand, tend to be denominated in megawatt-hours (MWh).

In terms of analysing capacity, and the reasons for possible diversity in its composition, a basic construct is the load duration curve. Figure 1.4 shows an annual load profile of average

![Figure 1.4](image-url)  
*Figure 1.4* Daily average electricity demand UK 98/99  
*Source: NGC.*
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Figure 1.5 Re-sequencing the load profile to give the load duration curve

Figure 1.6 Hourly load duration curve

daily demands, and it is clear that the average daily demand seems to lie within the range 24–43 GW. In Figure 1.5, this same data series, expressed now in hourly intervals, is re-sequenced according to decreasing daily loads, to produce the load duration curve. This load duration curve displays the number of days of the year for which the daily average load is greater than a particular level. Within-day variation would of course display an even greater range of demand on an hourly basis. In Figure 1.6, this same data series, expressed now in hourly intervals, thus displays the hourly load duration curve (note the points on the horizontal axis are now re-expressed as a percentage of the 8760 hours in the year).

For example, it is apparent that for 5% of the year the hourly loads are greater than 43 GW. In other words, if you owned a peaking plant, the running costs of which were so inferior that there was 43 GW of capacity on the system that could be offered more cheaply to the market, then you would only expect to run 5% of the time, which is to say that the “load factor” of this plant is only 5%. Obviously, it is only worth keeping this as an investment if you can gain a substantial margin over the running costs. So, it is easy to see why, in an imperfect market, prices become spiky at the peaks.
Table 1.1  Technology choice for a simple example

<table>
<thead>
<tr>
<th>Technology</th>
<th>Investment cost (£/kW)</th>
<th>Marginal production cost (£/MWh)</th>
<th>Life-time years</th>
</tr>
</thead>
<tbody>
<tr>
<td>Nuclear</td>
<td>1300</td>
<td>2</td>
<td>40</td>
</tr>
<tr>
<td>Coal</td>
<td>600</td>
<td>10</td>
<td>40</td>
</tr>
<tr>
<td>OCGT</td>
<td>200</td>
<td>30</td>
<td>40</td>
</tr>
<tr>
<td>CCGT</td>
<td>350</td>
<td>13</td>
<td>30</td>
</tr>
</tbody>
</table>

Figure 1.7  Annual cost of each plant for hours operated

In order to fix our understanding of the fundamental economics of the capacity mix, we proceed with a simple example. In Table 1.1, we have assumed a simple set of costs for four technologies, and let us presume an idealised situation where we can design the optimal capacity mix from these four alternatives in order to serve the above-mentioned load duration curve. We would expect nuclear to be baseload, and the open cycle gas turbines (OCGTs) to be peaking; coal and combined cycle gas turbines (CCGTs) will be somewhere in between (“mid-merit”); but how much of each we need is not obvious.

A simple concept is to look at the annual costs of owning and operating a unit (e.g. 1 kW) of each technology. The initial investment cost can be spread over the life of the plant by converting it into an annual annuity using the usual discounting formula, with an assumed cost of capital. This annual annuity value can then be considered the fixed cost of ownership per year. In other words, if you had to lease the plant from an owner, this is the annual rent that would just recover the owner’s investment at its cost of capital.

The annual operating cost is the fuel cost multiplied by the number of hours the plant operates in the year. Thus, at a 5% cost of capital (which was the case for pre-liberalised, public sector utilities), for two technologies, we get the annual break-even functions shown in Figure 1.7. We can see from this break-even chart that, under the assumptions of Table 1.1, a coal plant needs to run for more than 4000 hours per year to be a better investment than a CCGT. So, if we were just using these two technologies, how much of each do we install?
In Figure 1.8, we see how this break-even analysis can be projected onto the load duration curve to give the amount of each technology in the cost-minimising capacity mix. With just coal and CCGT, coal would be the baseload, to the extent of about 34 GW. With all four technologies, we get the break-even analysis of Figure 1.9. Thus, nuclear provides the baseload in an era of public ownership and access to low costs of capital (but if we went up to a “market” rate of 11%, there would be no nuclear or coal in the optimal mix, just gas CCGT and OCGT, as the higher cost of capital penalises the capital-intensive alternatives). However, staying with these 5% cost of capital results, for the purpose of illustration, after projecting these onto the load duration curve as above, we get a capacity mix of 65%, 4%, 16% and 15%, for the nuclear, coal, CCGT and OCGT technologies.

Figure 1.10 displays this capacity mix in terms of the stack of marginal costs, i.e. the supply function, which this simple system provides. The shape of the supply function is one of the most important fundamentals in understanding the behaviour of electricity prices. It displays the marginal cost of supplying power at a particular level of demand. Evidently, to the extent that market prices are efficient and reflect short-run marginal costs, this is a nonlinear driver of prices, depending upon demand in a particular hourly period. With demand being highly
variable throughout the day, the translation of this into prices via such a steeply-increasing supply function has an amplification effect in producing the hourly price volatility.

The key lesson of this simple example is that, for purely economic investment reasons, there may be a diversity of plant on the system, with increasing marginal costs for supplying the higher load periods. Of course the example is ideal, in assuming we can have a complete stock of new plant. In practice the capacity stock reflects historical investments over 40 years or more, each made at times when the cost and resource perspectives were quite different. So, there is further cost diversity because of these evolving structural changes in the perceptions of investment and running costs.
In addition, the above example makes a purely economic point. For technical reasons, some types of plant can respond to changes in demand quicker than others. Some plant, such as nuclear, need to run to a constant load. Other plant, such as large coal plant, can follow the load, but need a long time to start-up and so would not be useful for serving short-duration peaks. For technical, dynamic reasons, therefore, there is also a need for highly responsive, yet possibly expensive, generating plant to be available in the stack comprising the supply function.

Figure 1.11 shows marginal cost estimates for the England and Wales supply function in 1997, as comprised by the three main generating companies who were setting prices at the time. This is essentially the stack of plant above a baseload of some 20 GW, which was mostly nuclear plant and at the time would always be in merit. Compare this with Figure 1.12, which
is the actual supply function, which was offered to the market on January 20 of that year. In those days, the England and Wales market operated a pool system whereby all generators had to make offers from each of their plant for the whole of the 48 half-hourly periods of the subsequent day. These were then effectively stacked into a supply function for the day, and as the half-hourly demand fluctuated throughout the day, i.e. between the two vertical lines on the figure, a “system marginal price” (SMP), for each half hour, would be projected onto the vertical axis, as illustrated. Note that this SMP would then become the market price received by all generators in that half hour, such that the more efficient plant, with lower offers, received extra profit contributions from the differences between SMP and their offer prices. This is the uniform-price auction, characteristic of many pool-based markets, having the economic logic that the more efficient plant is likely to require a higher contribution to its investment costs. Even with less institutionalised markets, e.g. bilateral trading, price discovery should lead to the market price approaching that of the marginal producer’s.

Three important differences should be noted between the marginal cost supply function of Figure 1.11 and the actual market supply function of Figure 1.12. Firstly, as expected, the generators’ offers making up the market supply function are substantially above marginal cost. This is obviously the result of a lack of competitive pressure in the market, with the price-setting plant in 1997 being controlled by just three generators. The high prices therefore reflect a market structure issue, and perhaps also some tacit collusive market conduct. Secondly, we observe that not all of the plant was actually made available that day, so that the demand range extended into a steeper part of the supply function. In practice, in many parts of the world, capacity withholding by dominant players has been a constant issue for market surveillance. Because of the convexity of the supply functions, wholesale prices are very sensitive to the reserve margin between available supply and demand. Rather more subtle is the third observation that the slope of the supply function across the demand range is steeper in the market than marginal cost estimates would imply. This reflects the greater competition for load factor at lower levels of demand, and perhaps the greater ability of the generators to co-ordinate offers for the higher demand periods. All of these aspects together reflect a substantial strategic overlay to the fundamental economic drivers of price formation.

Furthermore, the strategic behaviour manifests a dynamic game, with the players repeatedly experimenting, learning and signalling through their daily offers. Figure 1.13 displays the series of subsequent weekday supply functions, from the three price-setting generators, following the day displayed in Figure 1.12. The evolutionary behaviour is quite evident.

Clearly, when it comes to analysing electricity spot price data, the challenge is to develop time-series models that are rich enough to capture both the nonlinear economic fundamentals and the stochastic behaviour induced by imperfect competition.

1.3 INSTITUTIONAL REFORM AND STRATEGIC EVOLUTION

Modelling and forecasting electricity prices is a totally new activity for the majority of companies in the energy business. Until recently, electricity was a monopoly in most countries, often government owned, and if not, highly regulated. As such, electricity prices reflected the government’s social and industrial policy, and any price forecasting which was undertaken was really focussed on thinking about underlying costs. In this respect, it tended to be over the longer term, taking a view on fuel prices, technological innovation and generation efficiency. This changed dramatically, however, during the 1990s.

Ownership has generally become private rather than public, competitive markets (pools and power exchanges) have been introduced for wholesale trading and retail markets gradually
liberalised to erode local franchises. Typically the industry has been split up into separate companies for generation, transmission, local distribution and retail supply. Transmission and distribution are network services and, as natural monopolies, are regulated. Generation is progressively deregulated as competition develops between a sufficient number of companies to promote an efficient wholesale market. Retail suppliers buy from the wholesale market and sell to customers. Industrial and commercial customers have generally been the first to receive full market liberalisation. The residential sector has been opened in many countries, but often quite slowly, and in some cases not at all.

All of this structural change has been motivated by a faith in the ability of competitive forces to create a more efficient and enterprising industry than either public sector or regulated monopolies could deliver. Thus, the most basic fundamental driver that we must keep in mind is institutional intent. Even in a privatised, apparently deregulated form, if the industry is not fulfilling government ideology and policy, it will be changed again. For example in the UK, there was a price cap imposed upon the pool during 1994–96, four years after its inception and a further two rounds of asset divestment required of the generators in 1996 and 1999 when it became apparent that their market power was not being sufficiently eroded by new competitive entry. Later in 2001, after a decade of accusations that the high pool prices were the result of market manipulations, the pool-based system was replaced by a fully decentralised bilateral trading system. These are clearly issues of what would normally be called regulatory risk. However, in the UK at least, they are essentially consequences of the strategic behaviour in the market creating a divergence from the institutional intent, which motivated the government. Markets may be liberalised, but such a sensitive industry as electricity continues to be more
carefully monitored than others. Price rises, which are tolerated in other sectors, quickly become regional and national issues of concern. Similarly, any prospects of power shortages become a major social and economic threat. As Indira Ghandi is once attributed to have remarked, “no power costs more than no power”.

One of the tragedies engendered by creating a new market by decree is that it is most likely to be incepted as an artefact of political compromise. Thus the privatisation processes of many countries are motivated by the fiscal objective of raising as much money as possible. Governments quickly realise that selling a few large companies will command higher prices than a large number of small entities. Companies operating in an imperfect market, where market power could be exercised and where the risk of bankruptcy is small, will sell at a premium and raise more money to offset government debt. Even if government revenue is not an issue, concerns about stranded assets or system security may prompt restructuring with more than the ideal amount of market power (e.g. Spain, California). So, even if efficiency via competition is the government rhetoric, we have seen new power markets persistently created with insufficient competition to drive prices down.

In seeking to understand electricity prices, we must first look at the fundamental economic drivers, and then assess this tension between regulatory tolerance and strategic opportunism. Thus, if we seek to relate the story of price behaviour in the England and Wales pool since the 1990s, it is one of strategic behaviour and regulatory reaction. Figure 1.14 shows the monthly average prices, alongside demand for the 1990–98 era of the pool. It is clear that despite demand being a fundamental driver of prices, this relationship does not have a high correlation during this period.

In 1990, the industry was restructured with the generation side of the market split up into only three main players, two of whom owned almost all of the price-setting plant. National Power was given about 48% of the fossil fuel capacity and Powergen 30%, with the remaining

![Figure 1.14](Image)

**Figure 1.14** Monthly demand and wholesale prices in England and Wales, 1990–1998
22% consisting mostly of baseload nuclear and some imports from France and Scotland. A set of contracts to safeguard the coal industry was initially incorporated into the privatisation, the effect of which was to encourage National Power and Powergen to bid quite low into the pool. By the end of 1992, however, with prices settling around £21/MWh, the regulatory office suggested that this was inhibiting new entry (the new entry price for gas-fired plant was thought to be about £24/MWh at the time). Prices thereafter moved up. By spring of 1994, the regulatory office suggested that prices of around £28/MWh were too high, and imposed a two-year average price cap of £24/MWh. A condition for this price cap to be relaxed was the divestment of about 17% of their mid-merit (price-setting) plant.

It was a shrewd regulatory policy to set an average annual price cap. The generators could not risk the consequences of not appearing to comply, yet for the market price to come in precisely at an annual average of £24/MWh does vindicate the accusation that they were collectively in total control of the prices. The prices did indeed average exactly £24/MWh over those two years. Clearly, prices, which responded to regulatory suggestions in such a sensitive and precise way, hardly reflected competitive market forces in action.

However, regulatory controls stimulate strategic reactions. Note the increased volatility of prices during the 1994–96 period. The average was 24, but the standard deviation increased dramatically. For 94/95, the standard deviation of pool purchase price (which is what generators received) was 30.8, compared to 7.7 the year before. This presumably reflected the rather complex interrelationships with contract positions. Volatility would clearly encourage contracting and risk premia to the generators’ benefit, at a time when average prices were being controlled. Price fluctuations, which were relatively higher during periods of the year where contract cover was relatively low, would also enhance generation revenues, despite the price cap. There was some evidence of generators being relatively over-contracted for the summer and under-contracted for the winter.

Figures 1.15 and 1.16 show the demand and price profile of the England and Wales pool for two very similar winter Wednesdays, separated by a year. The demand profile was almost the same, but prices were very different. The answer lies in the different supply functions that were offered to the market, Figure 1.17. Two things are remarkable about the comparison of

![Figure 1.15](image.png)

**Figure 1.15**  Pool prices and demand for Wednesday 19th January 1994
these supply functions. The first is that there is less capacity available in 1995. This can be seen as a shift of the function to the left as some of the mid-merit plant was taken out. More important, however, is the subtle change in the convexity of the function. In 1995 it became steeper, with lower prices at the baseload and a steeper function in the peaking zone. The result of this is much higher price volatility.
Finally, the balance of strategic behaviour and institutional intent undertook a regime switch to a new type of equilibrium in 2000. The regulatory policy of the 1990s had been moulded by the imperfect privatisation of 1990 and the duopoly market that followed, with the consequent imperative to encourage lower generator concentration and increase new entry. By 2000, this had happened. There was excess capacity by this time, and the previously dominant generators were very much smaller in market shares. But with the advent of retail liberalisation, they had sold off generating assets and bought retail customers, to become much more balanced as vertically integrated energy companies. Figure 1.18 shows how the price per retail customer increased as retail supply companies were being acquired.

Furthermore, once the major players became balanced between generation and retail, the issue of supporting high wholesale prices, in the face of obvious regulatory intent to bring them down, became less relevant. Indeed, if wholesale prices fell, government objectives would be achieved, and to the extent that retail prices did not follow, the vertical players were not worse off. Between 1998 and 2002, the wholesale prices, remarkably, fell by about 40%.\(^1\) The vertically integrated energy companies retained value in the retail market, as residential customers in particular did not prove to be active in switching suppliers, whilst most of the generation-only companies went into financial distress. Figure 1.19 shows how the price of generating assets fell during this period.

This chapter began with the observation that power plants are real options on the spread between power prices and the underlying fuel commodity. Clearly, the value of these options will decline with wholesale power prices, and that is what Figure 1.19 demonstrates. Within the supply chain, value moved to the least elastic part, the retail business. The strategic evolution will continue, however, and in 2003 there were already signs of the distressed assets being acquired and consolidated within the larger companies. These pro-cyclical market forces may well become an inherent feature of fully liberalised markets. To the extent that institutional reform of the sector was inspired by the ambition to make electricity rather more like other capital-intensive businesses, the extreme price sensitivity of the market to capacity margin, and the lead times in bringing in new capacity, would indeed appear to replicate the key ingredients for the emergence of business cycles, as we do see in other industries.

\(^1\) In Chapter 4, John Bower presents a more thorough discussion and an explicit econometric model for this event.
1.4 SUMMARY COMMENTS

This chapter has sought to provide a basic introduction to the fundamentals of price formation in the new electricity markets. In particular, the economic implications of synchronising the balance of demand and production creates a nonlinear, increasing supply function which translates demand variability into price volatility. The strong fundamental link to fuel commodity prices motivates convergence, and together with the seasonal regularities in demand, provides the source of mean reversion in the price series.

Electricity prices are politically sensitive and will ultimately reflect institutional intent. However, the strategic ambitions of companies are to make markets less efficient, and prices will emerge to reflect this delicate and transitory balance of regulatory control and strategic opportunism. Furthermore, the more liberalised the tolerance to market forces becomes, the more sensitive the system will become to the forces of cyclical behaviour.

From a modelling perspective, a consequence of understanding the microstructure of the price formation process is the realisation that there is a rich underlying structure which needs to be identified within the electricity spot price time series. The mean-reverting and volatility fundamentals are nonlinear, which together with structural nonstationarity, suggests that spot market behaviour may be better modelled from a set of adaptive regime-switching models, than from a single specification. The strategic opportunism and learning may induce a rich stochastic property to overlay these fundamentals. Forward price movements, however, to the extent that the markets become liquid and complete, may become well represented by models rather more similar to those seen elsewhere in financial markets. The ultimate interaction between forward and spot close to real time will, however, be quite different. Clearly, the research agenda for electricity market econometrics now becomes both timely and challenging.