ELECTRICITY AND ELECTRICITY MARKETS

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In this chapter we set out the features of electricity supply meriting special attention. This is followed by some fundamentals of market design and operation, both in general and for electricity markets in particular. The final section assesses the arranged marriage of economics and engineering represented by the creation of markets for electricity.[1]

INTRODUCTION

The generation, transmission and distribution of electricity have characteristics that, uniquely and otherwise, give rise to special considerations relative to the supply of other goods or services. In the main these hinge on the ephemeral nature of electricity and complications associated with the physics of electrical flows through interconnected networks, and they create the challenge of designing economic arrangements to suitably package electricity for sale using models of market-based exchange more easily applied to more typical goods or services. A number of these complications are "buried" when electricity is produced and allocated under some form of central planning and administration, but they become obvious when attempting to introduce forces of market competition into its creation and supply among voluntary, private-market participants.

WHAT IS SO SPECIAL ABOUT ELECTRICITY?

In General

Any special attention that is paid to electricity is not because it is intrinsically "essential". While most modern economies are in some part captive to electricity, this is because it is integral to our lifestyle and quality of life. Only in exceptional cases is electricity essential to life itself, so in this regard it must be distinguished from food, clean water and shelter. Also, components of the electricity sector traditionally thought of as "monopolies" are now regarded as being susceptible to the usual forces of competition, especially electricity generation and retailing but also (to lesser degrees) transmission and distribution. And certainly having "monopoly" characteristics is not itself that remarkable. So for electricity's special or distinguishing features, if any, we must look elsewhere.

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[1] A reader wishing to do justice to this topic might consult a more comprehensive coverage such as that in Stoft (2002).

Unlike virtually any other commodity, electricity cannot be stored on a significant scale given current technology.[2] Its supply and demand is instantaneous, with electrons flowing at the speed of light from generation to load – its ongoing delivery requires its ongoing creation. In fact it is only at the instantaneous level that electricity can be regarded as having commodity-like characteristics (i.e. having some measure of physical homogeneity), but even then its quality can vary across location because of the qualities of the medium through which it flows (i.e. the wires and other hardware in electricity networks).

The physical nature of electricity is defined in terms of features such as voltage (i.e. force), current (i.e. flow) – together, power – and, as is typical for electricity networks working with alternating (AC) rather than direct currents (DC), frequency.[3] While any single generator might be rated to produce electricity of precise electrical characteristics, once that generator's output is conveyed to demand via electrical wires additional factors then affect those characteristics. In the simplest case the electrical resistance of those wires gives rise to electrical losses (i.e. energy is lost as resistance in the wires causes them to heat). Furthermore, the characteristics of the electricity supplied will depend on the use to which it is put, with both supply voltage and frequency affected by the characteristics of the appliances and other equipment being supplied.

More important, however, is the fact that when one or more generators are connected to one or more electricity users via an electricity network the electrical characteristics of the system are then dictated by the nature of the network as a whole. The supply or use of electricity by any one party can affect the characteristics of electricity flowing through other parts of that network and to all other users.[4] Furthermore it becomes impossible in commonly used AC networks to control flows from source to load, with

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[2] Super-conductor and battery technology may one day improve to the point where useful amounts of electricity might be stored, but not in the foreseeable future. If and when it does, the economics of electricity supply will be markedly affected.

[3] A direct current (DC) is one in which electrical flow is constant with time, all other things (e.g. voltage, circuit resistance) being equal. By contrast, an alternating current (AC) is one which oscillates over time. An advantage of alternating currents is that they can be stepped-up using transformers to very high voltages which can then be transmitted over power lines – which have electrical resistance – with lower losses from heating than can lower voltages. These high AC voltages can then be stepped-down to usable voltages closer to load. Direct currents are not so easily stepped up or down, but can involve less losses than equivalent AC power flows. This arises because long-distance AC transmission is affected by another electrical property, capacitance, giving rise to "reactive power" that does not oscillate in time with the main AC flow, resulting in wasted power flows. For this reason high-power long-distance electricity transmission can more efficiently be achieved using direct currents, with the additional hardware costs being balanced by lower losses. This explains why power is transmitted between New Zealand's two main islands over a high-voltage DC (HVDC) link. See, e.g., FAQs at www.transpower.co.nz.

[4] In networks with alternating currents both voltage and frequency "give" when too much energy is demanded from available generation. A loss in frequency can be especially telling for generators whose plant operates with large spinning components designed to operate best at a certain rate, resulting in increased wear and tear. Considerations such as these give rise for the need for common quality standards and operating parameters in electrical networks.

electrons flowing throughout the network following physical laws,[5] and all generators simultaneously supplying all consumers.[6] Unlike other types of networks such as gas or railroads (or even some configurations of telecommunications networks), electricity networks do not involve the physical delivery of a given product to/from specified production/delivery points.[7] In other words, with electricity there is a mismatch between physical and contractual flows. It is therefore impossible to say that one particular generator supplying a given amount of electrical power supplied any particular quantity of electricity consumed.

Furthermore, the physical limitations of electricity transmission and distribution networks are such that their ongoing operation requires active monitoring of how much power is flowing along any given path (in simplest terms a transmission line can be thought of as a highly rated and expensive piece of fuse-wire). Since electricity supplied and demanded in a network must balance at all time, should any particular network path be "constrained" or removed from service (either to avoid or because of a fault), this can markedly affect the characteristics of the remainder of the grid, and the make-up of available generation and feasible demand. For an extreme example, loss of one section of the transmission grid might mean a certain number of generators can no longer be connected to demand, implying that existing demand must be supplied by other existing or additional generators, or simply cannot be met. In the latter case this excess demand might have the capacity to cause additional transmission failure, or to so significantly alter the characteristics of remaining power flows that it must be shed by the grid operator if the integrity of the transmission system and the electricity it supplies are to be maintained.[8]

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[5] For example, Kirchoff's laws summarise the natural propensity for electricity to simultaneously flow along all paths in a network – but with flows along each network path in inverse proportion to its resistance.

[6] As noted in Van Doren and Taylor (2004), such networks represent a form of "commons", the problems of which have long been familiar to economics and law. Chapters 9 and 10 discuss these issues further, as well as those of natural monopoly, "externalities", and "public goods" often ascribed to electricity networks.

[7] As noted in Joskow (1997), an electricity grid is not just a transportation system but a complex coordination system directed at meeting a vector of electricity demands using geographically dispersed generators and subject to stringent operating requirements to maintain network-wide electrical characteristics. It is for this reason that vertically integrated electricity systems have commonly been the preferred form of ordering around the world for much of the past century, internalising as they do the coordination and investment problems associated with electricity networks. With improvements in information and communications technology and advances in understandings of market design, however, more decentralised solutions are possible, facilitating competition where previously there was often otherwise monopoly.

[8] It should be noted that such systemic contagion effects are not wholly unique to electricity systems. Central banks are commonly concerned to see the prudential management of banking and other financial systems because of the possibility of failure in one part of the system creating devastating ripples throughout the rest. While such financial crises can develop quite rapidly they will not take place nearly as rapidly as in electricity networks, and in financial systems it is possible to interrupt specific financial flows in corrective ways that cannot be replicated for electricity flows. To extend the analogy further, however, it can be noted that inter-bank settlements depend on the combined solvency of a bank system's constituent banks, and that a central (or reserve) bank's ability to influence a bank system's liquidity to avoid any contagious insolvencies bears some resemblance to an electricity grid operator's access to ancillary services (see later) to maintain an electricity network's voltage and frequency.

An additional complication arises from volatility in electricity demand. While it is an involved exercise to coordinate multiple units of generation and transmission, and generator and grid reliability is such that available generation and grid capacity at the instant of supply can be forecast with some accuracy, the same cannot be said of electricity demand. Since physical flows of electricity to any one customer cannot be controlled by generators or lines operators (short of larger direct-connect customers being switched off or classes of customers having their supply limited), the actual amount of electricity demanded at any one instant is an unpredictable function of the combined instantaneous decisions of multiple electricity users.[9] It is for this reason that grid management is especially complicated, requiring the availability of either reserve generation or interruptible load available at short notice. A challenge in designing markets for electricity is to allow market participants to determine how best this should be achieved, as opposed to relegating such decisions to supply-focused "technicians" who cannot be expected to understand the differential effects of their system management decisions on multiple and heterogeneous electricity suppliers and users, let alone best know how to economically balance their varying and sometimes competing interests.

To make matters worse, most electricity users do not have access to timely and accurate information regarding how much electricity they are consuming and what their consumption will cost them. While larger consumers with considerable costs arising from their electricity usage have sufficient incentives (and, given current technologies, the means) to keep a close eye on cost efficiencies at the time of consumption, most users only discover this information long after the fact when they receive their monthly power bill, and even then often at fixed unit prices. As such, for most consumers electricity demand is typically loosely controlled and highly unresponsive to changes in electricity price, at least in the short term (if not longer).

These characteristics are common in electricity networks and are present no matter what the organisation of the electricity system.

In New Zealand

As discussed and illustrated in Chapter 3, electricity supply in New Zealand is subject to some additional distinguishing characteristics. By virtue of the country's geography and population concentrations, much of its generation capacity is located in hydro catchments in the South Island while electricity demand is located more in the north of the North Island. The transmission grid that typically transfers power generated in the south to demand in the north is long, skinny and sparse, as opposed to the more balanced, multi-path networks observed in other systems. It is possible that New Zealand's grid topology is less exposed to systemic failure than in more balanced grids

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[9] In New Zealand, for example, a sudden cold winter snap can lead to a correspondingly sudden increase in electricity demand as users turn on their electric heaters.

(e.g. with cascading failures such as that in the north-eastern US in August 2003), aided by the connection of the North and South Island grids via a direct current link.[10] As in any grid, however, New Zealand faces the potential for transmission constraints to complicate the coordination of the country's many points of electricity supply and demand, with physical isolation of various regions' electricity sub-systems from other parts of the electricity system occasionally arising.[11] The fact that New Zealand is geographically isolated from electricity systems in other countries and is therefore unable to export surplus electricity or import it in times of shortage only extends this complication to the national level.

Another distinguishing feature is New Zealand's reliance on a significantly higher share of hydro generation than in other countries (as opposed to coal, gas, nuclear or other forms of generation), and only limited hydro storage capacity. With electricity demand peaking in the cold winter months, this has the potential to cause supply shortages in years of low hydro inflows and/or high demands (such as those arising in especially cold winters).

There is also a "loss and constraint rental" associated with the supply of electricity under New Zealand's electricity market arrangements. In general, the supply curve for electricity will slope up as lower cost generation is supplanted by higher cost generation as more electricity is produced. In addition, the supply curve may rise when losses and congestion on the grid increase as throughput expands. New Zealand's wholesale market has "marginal-loss pricing" which means that electricity prices reflect the losses in transmission made on the last unit of electricity transmitted (a rental for scarce transmission capacity), further suggesting an increasing supply curve, particularly at any point in time.

Price-Inelastic Electricity Demand

Figure 2.1 illustrates a complication commonly associated with markets for electricity. Once again assuming that suppliers comprise multiple generators with varying supply costs, the supply curve can be represented as shown. Similarly it can be assumed that there will be some degree of negative association between electricity demand and electricity price, if only because some larger users have the technology to quickly change their consumption decisions in response to market price. Accordingly the demand curve for electricity should slope downwards to the right, as below, but it

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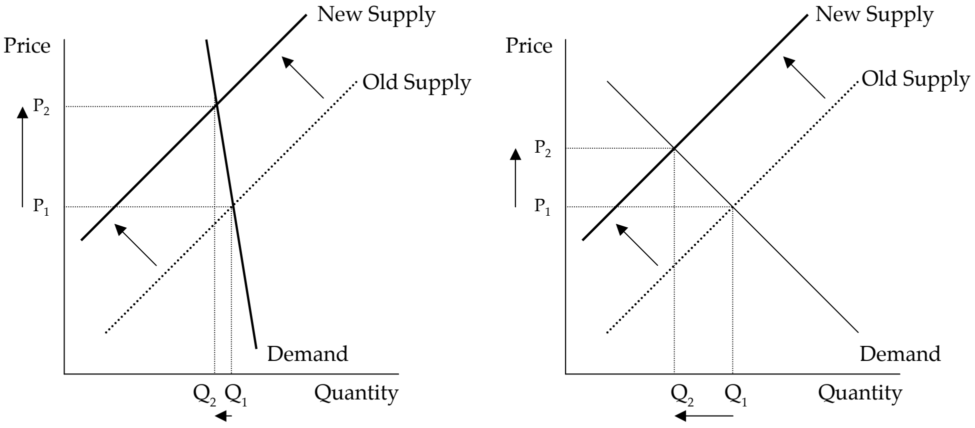
[10] Chapter 10 discusses the suggested merits of smaller AC networks separated by DC linkages, as opposed to large AC networks, one of which is that such an approach reduces the risk of failure on one part of the network affecting all other parts. Such DC interconnections can help to localise network failures, allowing the adoption of more aggressive grid operating policies, thereby increasing effective available grid capacity.

[11] Indeed, loss of the critical high-voltage direct-current link between the North and South Islands can and has resulted in the physical separation of their related sub-systems (see Chapter 6). A consequence of such separations is a reduction in the number of generators vying to supply demand in each region, and/or the number of consumers seeking supply, with the potential for either to exercise some degree of "market power", in the economic sense, under such circumstances (see Chapter 9).

is commonly argued that the unresponsiveness of aggregate electricity demand to changes in electricity price suggests that the electricity demand curve's slope is very steep (economists say that this means the "price elasticity" of electricity demand is low). Assuming that a major generator suffers an unforeseen outage, and so only more expensive generation is available to supply demand at any price – i.e. that the supply curve for electricity shifts up – Figure 2.1(a) illustrates what happens to the equilibrium electricity price and quantity when demand is unresponsive to price changes.

FIGURE 2.1 **Equilibrium Changes with Demand Un/Responsive to Price**



(a) Supply Shift – Demand Unresponsive

Contraction in supply **with demand unresponsive to price** results in small fall in quantity but large increase in price to maintain equilibrium.

(b) Supply Shift – Demand Responsive

Contraction in supply **with demand responsive to price** results in greater fall in quantity but smaller increase in price to maintain equilibrium.

Source: Richard Meade.

Figure 2.1(b) illustrates the corresponding changes if it can instead be assumed that demand is highly responsive to changes in electricity price (i.e. the demand curve is flatter). As should be apparent, for a given shift in supply the equilibrium electricity price is predicted to rise more sharply, and electricity consumed fall much less, when demand is less responsive to price changes. In fact, it is often argued that instantaneous electricity demand is essentially fixed, meaning that the demand curve for electricity can be represented by a vertical line at the quantity demanded, and that any change in supply conditions (i.e. shift in supply curve) feeds wholly through to price rises with the quantity demanded and supplied unchanged.[12] Analyses such as these are

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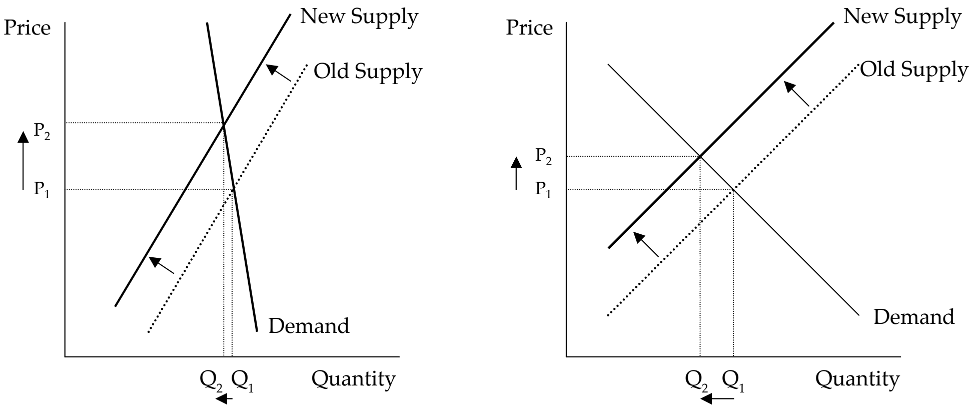
[12] Over the longer term, electricity demand should be regarded as more price-responsive as consumers have greater ability to adopt energy-efficient technologies and multi- or alternative-fuel appliances.

often used to back calls for regulatory or other changes encouraging greater price-responsiveness in electricity demand, or "demand-side response" (see Chapter 7).

Short Run versus Long Run

The distinction between short- and long-term supply and demand is illustrated in Figure 2.2. Just as electricity demand is often regarded as unresponsive to price in the short term, so too can the supply of various products. The supply of fresh foods, for example, is typically regarded as completely price-invariant in the short term, with harvested goods (e.g. fruit, vegetables, landed fish) being in fixed supply at the market place, and requiring immediate sale to avoid spoilage.[13] Short-term electricity supply is generally not so price-invariant, with generators typically having some capacity to increase output at short notice to meet increased demands, although this capacity might be limited because of limited fuel reserves. In the longer term, new generation can be built to meet growing demand, implying greater price-responsiveness (i.e. flatter electricity supply curve) than in the short term. Figure 2.2 illustrates how price changes in response to a change in short-term electricity supply (e.g. generator outage) should be expected to be greater than those arising to a longer-term supply change.

FIGURE 2.2 **Price and Quantity Changes in the Short and Long Term**



(a) Short Term

Contraction in supply **with short-term demand and supply both unresponsive to price** results in small fall in quantity but large increase in price to maintain equilibrium.

(b) Long Term

Contraction in supply **with long-term demand and supply both responsive to price** results in greater fall in quantity but smaller increase in price to maintain equilibrium.

Source: Richard Meade.

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[13] It is understandable that in such cases vendors simply try to achieve the highest price possible with available buyers, typically via some form of auction.

Decreasing Price Elasticity of Electricity Supply

A second complication often discussed in the context of electricity markets is the combination of demand being not responsive to price (i.e. "price-inelastic demand") and sharply rising costs of additional generation, particularly for generation "at the margin" or, in other words, that which is likely to be the plant represented by the point at which supply intersects demand. The latter can arise where the supply curve is comprised of differing generation technologies with rising output costs. An example of this is when hydro generation with low unit-production costs is followed by coal- or gas-based generation with higher running costs.[14] In this case the supply curve is upward sloping at an increasing rate, and so when this is combined with price-inelastic demand it is predicted that electricity price changes will be greater with movements in either supply or demand curve than they would be with elastic demand and/or more slowly rising supply costs.

Finally, while market supply and demand curves are usually thought of as the aggregation of individual supply and demand curves (just sum quantities at each price), electricity markets can illustrate this principle in reverse. This can arise, for example, when transmission constraints cause the electricity market to "regionalise" or fractionate into geographically distinct sub-markets. Figure 2.3 illustrates this scenario, assuming a grid like that in New Zealand, with the North and South Island grids connected by a HVDC link across the Cook Strait between them. Figure 2.3(a) represents the national electricity market, whereas Figures 2.3(b) and (c) present the respective regional submarkets arising, for example, when the HVDC suffers an outage.[15] In the South Island the supply/demand balance favours supply – with significant generation relative to local demand – whereas in the North Island it favours demand. Accordingly, when the North and South Island electricity markets "separate" because of an outage in the inter-island HVDC link, a rise in the electricity price is predicted for the North Island relative to the national price, whereas the South Island price is predicted to fall (as it did during a major loss of the link in early January 2004, with Christchurch prices falling and Wellington/Auckland prices rising; this is discussed further in Chapter 6 and is illustrated below).

Centralised Electricity Markets

Centralised electricity "pools" are commonly, but by no means always, the preferred market arrangement adopted in countries reforming their electricity sectors. They rely on optimisation models to determine which generation units to dispatch at the least overall cost, taking into account technical constraints such as the need to maintain network

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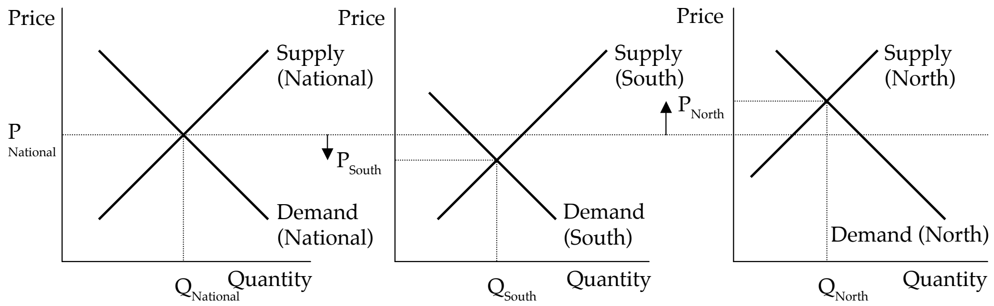
[14] The fuel (water) cost of hydro generation is typically low relative to other fuels; however, the capital cost may be much higher. Thus, once hydro generation is installed it is relatively cheap to run in all except dry years, but new hydro plants may be expensive relative to plants using other fuels.

[15] As it did for a number of days in early 2004, discussed further in Chapter 6.

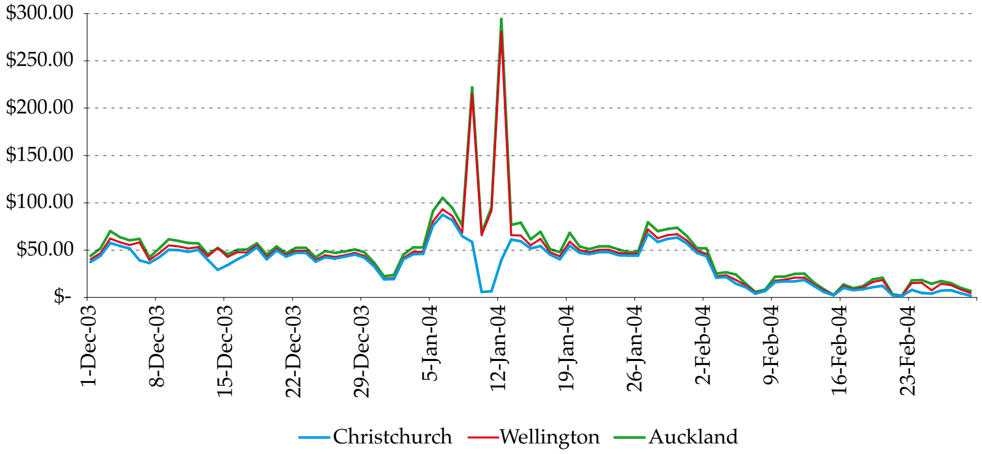
FIGURE 2.3 Price Separation Following Loss of Inter-Island HVDC Link

(a) National Market *(b) South Island Sub-Market* *(c) North Island Sub-Market*



When the national electricity market fragments owing to loss of the inter-island HVDC link, price is expected to fall for South Island electricity customers, for whom the supply/demand balance favours supply, and increase for North Island consumers for whom the reverse is true. Whereas the usual market aggregation technique would suggest that Q(N) = Q(Sth) + Q(Nth), the loss in HVDC link would likely result in Q(N) > Q(Sth) + Q(Nth), for example because of decreased generator competition and possible increases in transmission congestion elsewhere as alternative generation is redeployed to meet demand in each island.

Actual HVDC Loss in January 2004 – Main Centre Spot Wholesale Prices ($/MWh)



Source: M-Co data; and Richard Meade for (a), (b) and (c).

security. An obvious rationale for a centralised electricity market over decentralised alternatives is that it provides a clear way to coordinate electricity system operations, recognising the inter-dependencies between generation and transmission. When making transitions from electricity systems dominated by an engineering perspective it is not surprising that the market models adopted retain – perhaps too much so – a measure of centralised technical coordination. As one New Zealand writer put it: "The problem with the New Zealand electricity system is that 80% of production is hydro-electric, with only 12% of annual demand being storable. The problem of co-ordinating the reservoirs and inflows to avoid either shortage or excessive burn of thermal fuel must be recognised when creating competition".[16] An economist, of course, would suggest that a properly functioning market would provide the necessary price signals precisely to optimise such considerations, but at the same time take into account the all-important but missing variable in the engineer's equation, consumer preferences.

Such considerations aside, any reformed electricity system must involve some means to determine how generation is dispatched to meet demand at each point in time. The centralised approach does so explicitly, usually with some form of market-economics-mimicking model subject to technical constraints determining which generators meet expected demand at "least cost". This, of course, is not to say that electricity pools do, or do not, dispatch the economically optimal generation, but harks back to an engineer's mathematical programming model at the heart of central planning.[17] As it happens, the only features of electricity systems that need interfere with generation dispatch are those of technical feasibility (i.e. can dispatch take place within transmission operating constraints) and balancing (i.e. is extra generation, or load reduction, required to ensure instantaneous balance between supply and demand). Otherwise a decentralised market approach to determining which generators should meet demand is entirely feasible, and indeed occurs. Arguably it is also more likely to determine the economically optimal dispatch of generation to meet demand (see Appendix 2.2 for a case study on decentralised decision-making and the New Zealand electricity market).

Decentralised Electricity Markets

Examples of decentralised electricity markets include the New Electricity Trading Arrangements (NETA) operating in England and Wales since 2001, and the "PJM" interconnection area encompassing Delaware, Maryland, New Jersey, Ohio, Pennsylvania, Virginia, West Virginia and the District of Columbia in the US. NETA represents the almost polar case where 98% of electricity is self-dispatched through generators and consumers entering into bilateral contracts for delivery up to years ahead, whereas in PJM around 64% of electricity traded is self-scheduled.[18] A number of EU member states' electricity systems are based around such decentralised trading using power exchanges. By contrast around 20% of electricity traded in the New Zealand Electricity Market (NZEM) did so through bilateral trades, with the balance (80%) dispatched via a centralised pool. The National Electricity Market (NEM) in Australia is a compulsory pool through which all electricity is dispatched, representing the polar opposite to decentralised self-dispatch.

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[16] Boshier and Gordon (1996).

[17] Contreras *et al*. (2004) show that decentralised optimisations by profit-seeking companies with imposed balancing requirements can in fact lead to optimal and technically feasible generation dispatch.

[18] Zhou *et al*. (2003).

Comparing Electricity Market Types

Each approach has its advantages and disadvantages. Centralised pools allow the pooling of credit risks, which can be material when severe price rises cause market participants financial distress. They publish electricity prices that are transparent, and for electricity traded for short-term delivery – where electricity has the most uniform characteristics – provide economies of scale in transacting. Where pools coexist with bilateral trading, market participants have a means to compete away or "arbitrage" excessive spreads or pricing inefficiencies arising in either mode of transaction.[19] Pools suffer, however, from their rigid specification, which can create opportunities and incentives for "gaming" (see Chapter 9), and from their imposition of a stylised economic market model subject to technical constraints rather than simple reflection of an underlying market.

Decentralised electricity markets, by contrast, spurn the guiding hand of centralised dispatch in favour of providing means for parties to privately contract, with a centralised balancing market – covering just 2% of electricity traded in England and Wales, and 36% in PJM; and, even then, both NETA (like various other EU systems) and PJM allow market participants to transact for the necessary balancing. While decentralised bilateral trading need not involve the publication of transacted prices – which may in fact be the preference of some parties – the use of power exchanges to facilitate contract trading with published buy and sell prices (particularly since competing exchanges have been created) should be expected to yield economically efficient prices. Indeed, with advances in communications technology the problems of search, price formation and transacting (and indeed, grid balancing) are just as easily resolved via decentralised exchange as they are through pools. Under the decentralised approach credit-risk issues are borne more by individual traders than under a pool approach, but opportunities and incentives for market rules to be "gamed" are reduced, in some cases eliminated.[20]

It is possibly too early in the history of reformed electricity systems to determine which approach is superior. The shift from the centralised pool to decentralised NETA in England and Wales has been found to have had promising results in terms of price declines, although this has been attributed to other causes (see later). It has, however, resulted in a dramatic decline in reported abuse of market power and market rule gaming compared

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[19] Fixed price contracts of varying terms can be implemented for electricity delivered to the pool, by means of hedge arrangements. One very common arrangement is a contract for differences (CFD) that one party enters into with another at a particular location (node of the grid). If p is the nodal price then the CFD for an amount of electricity q requires that the seller (S) is paid (p*-p)q by the buyer (B). If the spot nodal price p exceeds (falls below) the strike price p*, S pays B (receives from B) the amount (p*-p)q. Hence if S receives the spot price on its sales, its revenue after settlement of the CFD is pq+(p*-p)q = p*q, and B's is -pq-(p*-p)q = -p*q. In effect, electricity is exchanged between S and B at the fixed strike price no matter what the spot price is for given quantity q. The CFD is a financial contract that virtually duplicates a fixed-price bilateral physical contract for electricity.

[20] Decentralisation may be sufficient but not necessary to mitigate gaming. Where centralised market rules are vulnerable to gaming, it may be possible to improve market rules so as to reduce this vulnerability.

with the previous market design.[21] A compelling lesson is that the decentralised approach – with only the barest of technical encumbrances – is indeed feasible.

ELECTRICITY MARKETS – HOW THEY WORK

Engineering Meets Economics

The need in AC electricity networks to preserve operating voltage and frequency in the face of instantaneous and unpredictable demand, while ensuring this does not breach critical operating constraints, requires continuous monitoring of grid-wide conditions and some means to procure supply/demand balance at all times. To the extent that market mechanisms are used to determine which generators meet demand at any point in time, those mechanisms must allow for all of these interdependent considerations. In the main these considerations boil down to mechanisms for coordination, and the extent to which centralisation is necessary to achieve this.

Electricity Market Architecture

Typically the required coordination is achieved by implementing an electricity market architecture that draws together a combination of "planned" and market-based components. The major players in this regard, detailed below, usually include a system/grid operator, and a market operator. In some cases the two players are combined, and sometimes also with the grid owner. Aspects of each player's roles might also be decomposed into finer roles, any or all of which might be undertaken either separately or combined with others.

System Operator and Ancillary Services

Since the transmission grid through which electricity flows must be physically managed to ensure operating constraints are satisfied, a **system/grid operator** maintains responsibility for physical operation of the grid and its security and supply quality. To do so it coordinates the actions of grid-connected parties[22] and typically contracts for **ancillary services**, for example, with generators to supply capacity on short notice, or purchasers to allow short-notice interruption of supply, to ensure that supply voltage and/or frequency is maintained within operating tolerances. This can be in response to contingent events such as transmission line outages, generators unexpectedly becoming unavailable, demand being unexpectedly high, other equipment failures, etc. Although such services are typically second-order in magnitude, they are critical to grid security and pose issues of market architecture.[23] In some pools, certain of the services

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[21] Zhou *et al.* (2003).

[22] In New Zealand these include generators, distribution companies and certain large industrial users.

[23] Indeed, Joskow and Tirole (2004) note that electricity prices can be very sensitive to small mistakes or discretionary actions by the system operator, with implications for capacity investments (discussed in Meade (2005)).

(e.g. reserves) are competitively determined alongside energy exchanged in the pool. The actual architecture for ancillary services can affect the operation of the pools if the competitive aspects of its provision are not recognised (i.e. it is important that ancillary services and wholesale electricity prices are jointly determined to mitigate issues of market gaming and ensure efficient prices).

Wholesale Markets, Market Operation, Scheduling, Dispatch, and Balancing

The next main component is the **(spot wholesale) electricity market** itself, whether organised around a **centralised pool** or a more **decentralised power exchange**, comprising some combination of real-time electricity trading, bilateral electricity trading in real time or for future delivery, and other markets to manage electricity price risks (e.g. hedge markets). Through the wholesale electricity market, generators and purchasers come together to determine how electricity demand is to be met in an imminent trading period. In a pool each generator effectively provides its own supply curve to a **market operator/administrator**, which often also takes demand curves from buyers (other times centralised demand forecasts are used). The market operator, as **scheduler,** aggregates this information into market supply and demand curves, seeking to identify the combination of offers and bids that meets demand at least cost while also satisfying any operable technical constraints relating to grid availability and security. The market operator might also be the **dispatcher** that instructs those generators required to meet actual demand arising in real time when they are to generate. As **pricing manager** the market operator centrally determines and disseminates electricity prices. By contrast in an exchange, generators and purchasers contract bilaterally for supply, and to cover any imbalances in supply and demand affected parties are required to pay for top-ups via a **balancing market**, usually managed by the system operator.

Centralised wholesale electricity markets, involving the bulk transacting of power, can be set up with **voluntary ("net") or compulsory ("gross") pools**. Under voluntary arrangements parties may also trade bilaterally; with compulsory market participation such trades are precluded. Either way, parties are usually free to enter into financial contracts to manage their exposure to wholesale electricity price movements. From 1 March 2004 the NZEM pool was deemed by regulation to be a compulsory pool, with an exception being the major aluminium producer, NZAS, which has long-term contracts in place for the delivery of electricity.

Wholesale Market Types

Where pools or other centralised markets are used (such as for ancillary services), generators can be paid a single price representing that which ensures supply and demand coincide – an arrangement known as **"uniform pricing"** – or receive the prices that they bid for each unit of generation they offered for supply – known as **"pay as bid".** The relative merits of each are discussed further in Chapter 9, but for now it is noted that both approaches are vulnerable to participant "gaming", and each has its own implications for the prices expected to result from its application.[24] Wholesale trading can be **real time**, or **spot,** in which electricity is traded in short time intervals (e.g. hourly or as short as five minutes), with this term sometimes being applied to **hour-ahead** or **day-ahead** markets (in which prices are determined in advance of the actual period of supply and demand). Wholesale prices can also be ***ex post*** or ***ex ante***, respectively referring to whether **final prices** are determined after the fact – as in New Zealand when actual demand is known and hence actual prices determinable – or before, in which case additional payments are required to reflect actual market circumstances (e.g. by market participants making payments to a system operator if it buys or sells power to ensure continuous balance of supply and demand, or by market participants accessing a balancing market to cover their own imbalances under a more decentralised approach). Under the *ex post* approach indicative prices are provided up to the time of dispatch.

Hedging

In addition to the spot/real-time market, it is also possible for electricity to be traded in **forward markets**, in which supply is contracted-for in some future period beyond that of the spot market. To manage the risks of wholesale electricity price movements, both contracts for physical electricity delivery and financial contracts referenced off electricity prices can be entered into, collectively known as **hedge contracts**. **Financial hedge** contracts include contracts for differences, in which either party to the contract makes payments to the other based on a relevant reference variable such as the spot price. If such parties transact on the spot market the arrangement serves to fix the price of electricity for one or the other or both at whatever price is struck under the financial contract. **Physical hedges** can include a generator contracting with customers to make physical supply at a fixed price, in the case of residential electricity customers without fixing supply quantities. Finally, to ensure electricity supply security (as distinct from grid operational security) it is also possible for market participants to be contracted to provide reserve generation capacity to be available when called upon whenever supply otherwise offered into the market is short of demand, for example, by the system operator, market operator, some other (e.g. government) agency, or market requirements.

Zonal versus Nodal Pricing – Losses and Congestion

To increase the dimensionality of such markets, elements of the above need not be confined to the national level. Price-setting for the wider electricity system can be decomposed into regional sub-markets (setting **zonal/regional prices**) or further, for example, to the level of individual injection and off-take points around the grid

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[24] See, for example, the difference between uniform-price pay-as-bid auctions described in Chapter 9. The pay-as-bid auction has essentially the same price-determination features as bilateral contracts in that the relevant parties enjoy a measure of pre-determined outcome.

(so-called **locational/nodal pricing**).[25] To account for the fact of transmission losses, **average** or **marginal losses** can be charged to pay for the additional power that must be supplied to meet demand around a grid that has resistance. Under the former, purchasers are charged an averaged allowance for the additional power required to overcome losses. Under marginal-loss pricing, the extra costs of losses relating to given locations determine prices paid by users at those locations, thereby mimicking desirable operation of markets by enabling participants to balance extra resource cost against the benefit of another unit of electricity. The cost of transmission constraints is similarly observable under nodal pricing, with nodes suffering congestion due to constraints yielding electricity prices higher than those without.[26] To help market participants hedge the risk of transmission price rises due to constraints and losses, instruments such as **transmission congestion contracts (TCCs)** or **financial transmission rights (FTRs)** might also be offered and traded.[27]

Linkages to Other Markets

More generally, electricity markets are clearly, if indirectly, linked to many other markets. In New Zealand as elsewhere, the prices of generator fuels such as coal and natural gas (or even oil) interact with electricity-market prices. Given the dominance of hydro-based generation in New Zealand, and the emerging appreciation that competition for available water uses for activities such as agriculture and tourism means that water is a scarce and increasingly valuable resource, Box 2.1 discusses the link between markets for electricity and markets for water. Moreover, the market price of commodities for which electricity costs constitute a major share of production costs (e.g. aluminium smelters) influences whether their producers should demand large amounts of electricity (pushing up electricity prices), or shut down when prices are too high. Thus both input and output markets affect the price of electricity; and distortions in such markets, such as long-term gas contract prices, or lack of market prices for water, will similarly affect electricity markets.

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[25] By virtue of network interconnection the zonal/regional representation of a network can reflect a "hub and spoke" contractual decomposition of the full nodal representation. In other words, a zonal representation can be created by trading around only a subset of nodes, with prices at remaining nodes still remaining informationally efficient. It is interesting that the physics of electricity movement mean that the prices at nodes represent (general equilibrium) economic prices no matter the volumes of offtake or injection at these nodes. Analysis by Evans *et al.* (2003) suggests that the NZEM can indeed be considered an integrated market by virtue of observed correlations between reference and other nodes.

[26] When a section of transmission grid becomes constrained (i.e. operating beyond its technical limits), more expensive generation downstream of the constraint must be substituted for cheaper generation upstream, resulting in higher electricity prices in the downstream region.

[27] Both types of contract pay their holder an amount based on the difference in electricity prices between specified grid nodes at a given level of power flow. FTRs are "revenue adequate" TCCs issued by the grid operator and funded by transmission constraint and loss rentals (see Chapter 9 for more). As discussed in Hogan (1998), the two leading electricity market configurations involve either a pool with FTRs, or a bilateral market with tradable physical transmission rights.

BOX 2.1

Link between Electricity and Water Markets

Electricity markets in many countries around the world now have an important role in the scheduling and allocation of generation across load. In addition to their part in electricity allocation, they can play a role in the allocation of water through water markets. Water markets allow secure property rights or entitlements to water to be traded between water users. While some parts of the world have allocated water resources through water markets for a considerable time (e.g. many of the drier western states of the US), markets are becoming more popular as a means of efficiently allocating scarce water resources in the face of increased water demand. Countries such as Australia, the UK, Chile and Mexico have all recently introduced measures to facilitate trading in water rights.

The link between electricity markets and water markets is provided by electricity prices in an industry with significant hydro generation. In spot and longer-term contracts electricity prices provide the value of water on a river with existing hydro-generation. This, in turn, provides a minimum value of a water right for any use on such rivers.

Consider a point on a river upstream of a single hydro power station. At this location, the value of water to the hydro-generator is given by the price at which it sells electricity, less the cost of any resources used (which is very low in the short term when plant is fixed). If the value of water in some alternative use were lower than this price, an efficient water market would ensure water is allocated to the higher valued use of electricity. Hence, the wholesale price of electricity at the relevant network node provides the link to water markets by giving the minimum value of water at points on the river upstream of the power station.

The minimum value of water provided by the electricity market applies both across the country and across alternative electricity generation fuels. The effect across the country is illustrated by the case where hydro-lake inflows have been low in one region and high in others. The price of electricity at any location reflects the higher electricity production in regions with relatively lower scarcity of water, and vice versa. Thus, the price of electricity determines the minimum value of water across different hydro locations.

For the effect across alternative fuels, suppose that gas were setting the price of electricity, then gas will also be determining the value of water in electricity generation. This occurs because if one more unit of electricity is supplied by hydro-generation, the benefit is the price of the gas-supplied generation substituted for. Hence, if the price of gas increases then the value of water in generating electricity would also increase. The value of water in electricity generation is generally no more or less than that of the price of electricity, be the price set by hydro or other fuels.

Source: Adapted from Counsell and Evans (2004).

TABLE 2.1 Market Arrangements Compared ...

Arrangement	*England and Wales*		*Australia*	*US*	*New Zealand*
	Pool (1990 - 2001)	*NETA (from 2001)*	*NEM (from 1998)*	*PJM (from 1997)*	*NZEM (1996 - Feb. 2004)*
System/ market operation	Grid owner is also both market and system operator.	Grid owner is system operator. Two independent market operators plus informal markets.	National Electricity Market Management Company (NEMMCO) owned by participating states is system and market operator.	PJM, owned by utilities and non-utilities in its connection area, is independent system and market operator.	Transpower (grid owner) is system operator, scheduler, and dispatcher under contract to NZEM (multilateral contract). Market operator M-Co acts as market administrator, and pricing and clearing manager.
Self-scheduling	0%	98%	0%	64%	20%
Bilateral trading	Disallowed, although bulk of electricity traded is covered by financial hedge contracts.	Yes, by definition. Generators and purchasers trade on forward and futures markets up to years ahead, and through power exchanges closer to actual trading period.	Generally disallowed, although financial hedging permitted.	Allowed.	Allowed, and energy traded through NZEM often hedged.
Demand-side bidding	From 1994 – previously system operator used own demand forecasts.	Yes – generators and purchasers trade bilaterally.	Limited to scheduled/fixed loads.	Yes – most generators and purchasers trade bilaterally.	Yes – generators and purchasers submit offers and bids.
Pricing	Ex ante, day-ahead, spot in half-hour trading periods.	Ex ante, up to years ahead, for half-hour trading periods.	Ex ante, day-ahead, spot for five minute intervals in half-hour trading periods.	Ex ante, day-ahead for hourly trading periods.	Ex post, day-ahead, spot in half-hour trading periods. Final prices posted next day.
Day-ahead market	No.	Yes, by virtue of forward bilateral trading.	No.	Yes (15% of demand), with real-time market (21% of demand) for balancing.	No.

TABLE 2.1 CONT'D **… Market Arrangements Compared**

Arrangement	*England and Wales*		*Australia*	*US*	*New Zealand*
	Pool (1990 - 2001)	*NETA (from 2001)*	*NEM (from 1998)*	*PJM (from 1997)*	*NZEM (1996 - Feb. 2004)*
Price cap	1995 and 1996 only.	n.a.	Yes, triggered when NEMMCO intervenes to restore balance.	Yes, in energy and ancillary services markets.	Effectively yes, within limits, from June 2004.
Ancillary services/ balancing	Done by system operator (e.g. contracting for reserve generation, interruptible load, etc), with uplift included in pool price to cover.	Generators and purchasers buy or sell deviations from notified positions from system operator in real-time balancing mechanism at potentially unfavourable imbalance prices. System operator ultimately responsible for balancing via balancing market or by procuring ancillary services ultimately funded by market players.	Done by market (i.e. system) operator via ancillary services contracts, ultimately funded by generators and customers.	Decentralised using automatic control signals to selected generators, since June 2000. Market-based mechanisms replaced administrative and cost-based system.	Done by system operator via ancillary services contracts, with reserve component being reflected in nodal electricity prices.
Losses	Averaged across system and uplift included in pool price.	Averaged across system and reflected in imbalance prices.	Annual average zonal loss factors applied to regional prices.	Marginal losses reflected in prices at each of 1,750 nodes.	Marginal losses reflected in prices at each of 244 nodes.
Transmission congestion hedges	No.	No.	NEMMCO auctions congestion rents.	FTRs (i.e. claims on congestion rents) are auctioned annually.	FTRs mooted.
Reserve capacity	System operator procured via capacity payments.	Excess capacity in 2001 (i.e. reserve margin) was 33%, but wholesale price declines threaten viability of nuclear generation.	Minimum regional generation reserve margins specified by NEMMCO.	Retailers required to own or acquire own peak loads plus around 18% reserve margin.	Electricity Commission to contract for reserve generation and interruptible load funded by industry levy from June 2004.

Comparing the NZEM with Other Electricity Markets

Table 2.1 provides a brief comparison of market arrangements in the NZEM (until 1 March 2004, when the Electricity Commission assumed industry governance and a gross pool replaced the hitherto net pool) with those in a sample of other reformed electricity systems. The New Zealand arrangements are compared with those in England and Wales (both the Pool that operated from 1 April 1990 to 26 March 2001, and the New Electricity Trading Arrangements, NETA, operating since 27 March 2001), PJM, and eastern and southern Australia (National Electricity Market, NEM).

As illustrated in the table, even within centralised electricity pools there can be significant variation in details. The England and Wales pool operating under early reforms represented a much more supply-side-focused arrangement than that in other countries, or under the later NETA. Whereas the demand side played no active role under the initial setup, under all other arrangements surveyed there were at least some electricity purchasers playing an active role – either by submitting bids into a centralised pool or by bilateral and power exchange trades under NETA and PJM; and also by providing interruptible load for ancillary services (the more so under NETA's balancing mechanism which also accesses supply or demand reductions via power exchanges).

NETA, mirroring arrangements in various other EU states, represents the extreme counterpoint (and PJM less so) to the other examples, based around decentralised bilateral energy trading with self-dispatched generation in which both generators and purchasers bear responsibility for ensuring system balance (which remains coordinated by the grid-owning system operator). Centralised market operation is typical elsewhere, in addition to centralised grid management. Significant variation remains as to whether physical trading can occur outside of the centralised markets, and in the scope of the system operator's role. Price caps of various sorts are present in some systems (as in parts of the US, and the Australian NEM). New Zealand's use of *ex post* pricing is an exception: it favours pricing based on actual electricity flows determined after the fact, over price certainty for traders before the fact but subject to *ex post* adjustments.

Even within centralised pools there need be no consistency in matters as fundamental as the nature of offers and bids. Under the England and Wales pool (initially only) generators would submit bids, being complex nine-part offers including separate allowances for fixed start-up costs, a no-load price and a "must-run" flag. In the NZEM, by contrast, these technical factors are internalised in price and volume offers – for example, zero prices are allowed to ensure "must-run" plant is dispatched (e.g. to meet requirements of resource consents for minimum hydro river flows).[28] Pool prices in England and Wales would also include allowances for a number of other factors, such as capacity payments, and uplifts including availability payments and for transmission services (such as ancillary

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[28] At zero prices the right for generation to run is allocated by means of generators' willingness to pay as revealed in a prior "must-run" auction. This mechanism is required for situations of excess supply at zero price.

services). NZEM prices, by contrast, include additional allowances for (as an example) reserve generation,[29] but tend to rely more on nodal pricing to reflect other factors such as transmission losses and constraints.

As discussed in Chapter 4, NETA came about in response to perceived shortcomings in the England and Wales pool operation, particularly as regards the ability of generators to "game" the pool and drive up prices.[30] Similar allegations have been made regarding the NZEM, particularly in winter power shortages (see Chapter 6) and/or when transmission constraints cause the electricity market to fragment, thereby affording generators greater opportunity to manipulate prices (see Chapter 9). The types of strategies used under pool arrangements to increase electricity prices (see, e.g., Bower (2002)) would appear to reflect not only a combination of particular market arrangements (such as the extent and timing of generators' ability to amend their commitments prior to trading periods, and/or to play off the spot market against the capacity or reserves markets) but also fundamental features of market architecture (such as whether purchasers participate in the pool at all and can therefore react to generator offer prices, whether there is a day-ahead market that contracts generation forward and reduces incentives to game spot prices, and whether the system operator or market participants bear the responsibility for imbalances).

ELECTRICITY MARKETS – DO THEY WORK?

At the technical level the answer to this question has to be "yes". After shifting from centralised administration of electricity systems to less planned and more market-based solutions, the lights have not gone off (at least not because of this). It is revealing to see that the decentralised market-based mechanisms adopted under NETA and in PJM have been as effective in terms of supply security as the centralised pool approach adopted by countries and states reforming their electricity sectors. While centralised coordination of the physical electricity system remains the norm via a system operator, electricity markets of varying stripes show that the free-acting forces of supply and demand at a decentralised level can be relied upon to identify trades that enable system balance to be maintained, given suitable market architecture.

A more open question is how well electricity markets work in terms of their goals of providing an effective means for competing generators and purchasers to transact at efficient electricity prices both now and over time. As discussed in Chapter 9, different market arrangements can be predicted to perform better or worse than others, in specific circumstances if not generally, which will be reflected in the level, trend and volatility of electricity prices. And this performance cannot be viewed simply in terms of market architecture; it also should be viewed in the light of broader electricity market structure,

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[29] In fact, reserve prices are jointly determined with energy prices in New Zealand so that the trade-off in competitive provision is reflected in their prices.

[30] For a critical analysis of NETA and comparison to the England and Wales pool it replaced see Henney (2001).

participant behaviour, regulation and so on. In this regard the England and Wales re-reform experience is particularly helpful, as its electricity market performance over time can provide greater insight into the effects of changes to mechanisms, industry structure and regulation.

Bower (2002), for example, examines the path of wholesale electricity prices in England and Wales under the 1990-2001 pool and NETA over 2001-2002, seeking to determine whether price declines in the latter period can be said to derive from the change in market mechanism, or reflect the ongoing effects of other restructuring. As shown in Figure 2.4, early prices rose under the pool, and remained higher than the estimated marginal cost of production despite theory predicting they should fall to that level (possibly reflecting a political bias towards coal in the early reforms, but also encouraging unnecessary investment leading to over-capacity). Using statistical analysis Bower finds that the shift to NETA resulted in no significant decrease in prices, except by the removal of capacity payments. The observed price declines were found to be most associated with structural changes (coal plant divestments), increasing use of cheaper imported coal, and overcapacity arising from the construction of new gas plant.[31] Bower surveys the range of early views expressed on the efficacy of NETA, noting that even the relevant regulator has softened its initial positive stance, and concludes that the proposed extension of NETA to Scotland in 2004 is unlikely to benefit consumers (through lower prices) unless the current duopoly in Scottish generation is broken. Zhou *et al*. (2003) report, however, that since the introduction of NETA price volatility has reduced, and the gaming and market-power issues that plagued the former England and Wales pool have all but vanished.

By contrast, Wolak (1997) finds that both market structure and market rules affect the behaviour of competitive electricity prices. Examining evidence from England and Wales (pool), Norway, Victoria, and New Zealand for 1990-1997 (i.e. including less than one year of NZEM operation), he found that electricity systems dominated by fossil fuels rather than hydro power tended to experience greater price volatility within years, as do industries with a larger share of private generation and markets with mandatory participation. Systems dominated by fossil fuels enjoyed greater stability in mean electricity prices across years, reflecting the vulnerability of hydro systems to variations in the weather and the greater degree of integration in international markets for oil, gas and coal. Wolak tentatively concluded that even with large state-owned rather than private firms dominating the NZEM and Norway, prices in these markets appeared to be affected by market power, with large state-owned generators acting as market leaders and other firms acting as a competitive fringe. He found that markets with less government ownership were associated with lower average electricity prices.

Support for the decentralised approach adopted under NETA is provided by De Vany and Walls (1999). Noting that US electricity reforms are tending towards the centralised

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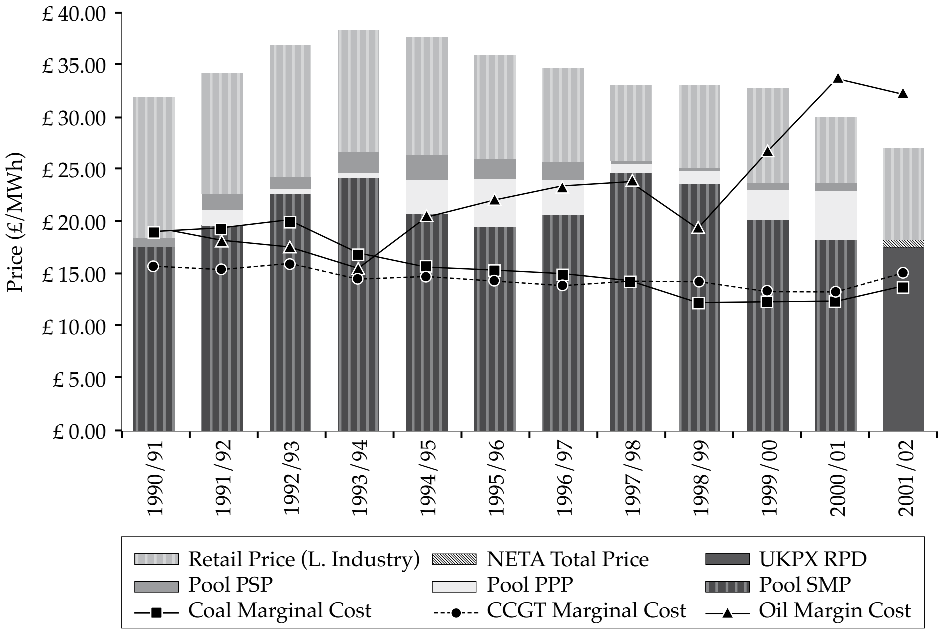
[31] Indeed, wholesale electricity prices fell sufficiently by 2002 that nuclear generation was no longer viable and faced bankruptcy, and some coal and gas generation capacity was withdrawn.

FIGURE 2.4 **England and Wales Mean Electricity Prices and Costs 1990-2002**



Retail Price = *DTI Quarterly Energy Prices*. Table 3.1.2 Prices of fuels purchased by manufacturing industry (www.dti.gov.uk/energy/inform/energy_prices/) with quarterly price for Large consumers in £/MWh calculated from formula p/kWh *10 then averaged over Q2, Q3, Q4 plus Q1.

Marginal Costs = *DTI Quarterly Energy Prices*, Table 3.2.1 Average price of fuels purchased by major UK power producers (www.dti.gov.uk/energy_prices/) with quarterly marginal costs in £/MWh calculated from formula p/kWh *10 / Thermal Efficiency (coal 33%, CCGT 45%, oil 30%) then averaged over Q2, Q3, Q4, plus Q1.

Pool prices = Statistical Digest (www.elecpool.com) with prices in £/MWh averaged over Month 4-12 plus Month 1-3.

NETA Total Price = *UKPX* RPD (www.ukpx.co.uk) plus Balancing Mechanism Cost (from anonymous correspondent) with price in £/MWh averaged over Month 4-12 plus Month 1-3.

Source: Bower (2002).

pool approach, they note that such a degree of coordination, given current information and communications technology, is computationally prohibitive (requiring up to 18 hours simply to determine optimal dispatches). Citing the existence in the US of a successful decentralised model operating in the Western Systems Coordinating Council, they explore the pricing dynamics of an interconnected but decentralised network of electricity markets, following unregulated wholesale power prices in an eleven-state trading region. Their results suggest that such an architecture produces stable and efficient prices, and results in a convergence in prices across electricity markets similar to that experienced in the US deregulated gas markets. In other words, decentralisation is predicted to be an effective approach even in complex networks of interconnected electricity markets, not just within a single system such as that in England and Wales.

Turning to the NZEM in particular, Hogan (2002) described the NZEM arrangements as being in many ways "at the forefront of best practice", and in terms of its real-time operations "aligned with the best international practice for a competitive electricity market". He identifies the New Zealand market's major missing ingredient to be a system of long-term transmission rights (such as FTRs) which are increasingly being employed elsewhere (e.g. PJM and the Australian NEM, which has a form of FTR for interstate connections). FTRs reduce the short-term volatility of prices between nodes, which is particularly useful in markets with marginal loss pricing as it enables the price certainty of hedges at particular nodes to be extended to other nodes without specifying hedges at all such nodes. While NZEM's use of nodal pricing provides clear signals of the cost (or value) of transmission losses and constraints, the lack of such instruments – which allow their holders to capture a proportion of the benefits of relieving these losses and constraints – is an obstacle to market-based solutions to grid investment.[32]

Market research by the Energy Efficiency and Conservation Authority (EECA (2002)) identifies a desire by electricity users for a firm day-ahead market, in which electricity prices can be locked-in one day forward, allowing sufficient time for consumption plans to be adapted accordingly. Counsel and Evans (2003) support this conclusion, identifying benefits from such a market to include: greater supply security and efficiency, with generators better able to manage their supply commitments (particularly for plant with long start-up times); enhanced demand-side participation and price-risk management (see Chapter 7) – more so than with standard hedging arrangements, since day-ahead markets should be deeper than longer-term forward markets; and reduced incentives for any generator gaming of the spot market because committed forward or hedge prices remove price effects of gaming in the short term.

Finally Evans, Guthrie and Videbeck (2003) examine whether transmission constraints can segment the NZEM and thereby increase opportunities for localised generator gaming or other exercise of market power. They examine the degree of price integration between seven selected nodes in the NZEM for 1997-2002, finding some time-of-day and locational market segmentation, but concluding that the NZEM over the majority of the sample period was integrated. Such findings provide a measure of reassurance that pricing electricity at 244 nodes around a grid subject to sometimes persistent constraints in a relatively small electricity market is not unduly diffuse.

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[32] See Evans and Meade (2001) for an analysis of FTRs proposed for New Zealand. Marginal-loss locational pricing, while appropriately pricing electrical energy lost in transmission, does produce relatively volatile prices in response to changes in demand and capacity, as losses increase at a faster rate than an increase in throughput.

CONCLUSION

Despite the unusual complications associated with the operation of interconnected electricity networks, engineering difficulties have not proven insurmountable in countries seeking to inject competition and market forces into their electricity sectors. Industry structure has proved as important as market mechanisms and architecture, combining to influence the pricing behaviour in reformed sectors. Importantly, the meeting of engineering and economics – involving the relinquishing of some measure of control by electricity system operators to the anonymous, diffuse and apparently indefinable forces of market-based competition – has not caused the lights to go out. Indeed, as discussed in later chapters (e.g. Chapter 6), evidence exists for system security to have improved under such decentralised administration.

In terms of market mechanisms and architecture, it is arguable that market-oriented electricity reforms have been unduly cautious, with centralised electricity pools initially being the norm and decentralised bilateral exchanges only recently being implemented at the market-wide level. Such a caution is an understandable consequence of long-standing domination of electricity system operation by an engineering preference for control and coordination, and politicians fearful of the lights going off, struggling to balance the equal impenetrability of engineers' caution and economists' optimism about the efficacy of seemingly nebulous markets.

Such caution has commanded a price. The strict centralisation of the England and Wales pool, combined with its initial lack of demand-side market participation, system operator responsibility for balancing, inadequate early structural reform, inadequate market rules, and undue generator discretion, created the perfect "turkey shoot" for generators of a mind to game the market rules for profit. As discussed in Chapter 9, the more the market rules specify detailed elements and constraints, the greater the scope for structural flaws precipitating price manipulation.

NETA might be argued to represent an overreaction to the pool's flaws (although PJM would not), with more efficient pool models having successfully operated in New Zealand and elsewhere (e.g. Norway). But NETA and some other EU state models both demonstrate that an aggressively decentralised market architecture is feasible – allowing network coordination without requiring a centralised market – and that it carries the promise of reduced (and/or transformed, if not eliminated) exposure to any generator market power. At the same time they illustrate the potential for electricity-user participation (e.g. via electricity exchanges), one of the holy grails of electricity sector reform worldwide (see Chapter 7). The complexities of US-wide reform might prove a useful laboratory for the decentralised market approach, particularly if the computational difficulties of the centralised model are not surmounted.

Finally, the performance of PJM/NETA-like systems relative to centralised pool-based systems will be an important area of research, influencing the course of future electricity sector reforms, both in countries and states already reformed and those whose reforms are yet to commence. As for the England and Wales pool, it is too much to expect that NETA will prove to be the best model of decentralised electricity markets, so future refinements should be expected. The disastrous reforms in the Californian electricity sector, discussed further in Chapter 4, involved a hybrid model of the centralised and decentralised approaches, but flaws in the centralised parts of the system, and some regulatory constraints, most critically contributed to its failure. At present the NZEM is making no moves towards greater decentralisation (in fact Chapter 8 argues the reverse to be true), but for reasons discussed in Chapter 9 there is a case to be made that it should.

APPENDIX 2.1 – A BRIEF TAXONOMY OF MARKET TYPES

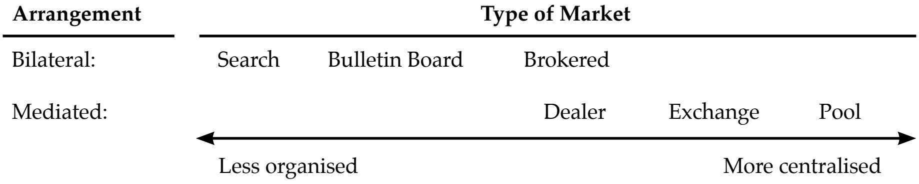
INTRODUCTION

Again it is left to Chapter 8 to provide a discussion of the place of different decision-making mechanisms. Here a scheme is proposed – following that of Stoft (2002) – to place the development of electricity markets in context, taking as distinguishing the degree of centralisation or decentralisation implicit in any given set of market arrangements. While "market architecture" is taken to refer to the array of interconnected markets and submarkets that constitute a market-based mechanism of exchange for any particular good or service, "market type" is used to refer to the mechanism that a market uses to determine how exchanges are made (e.g. how price, quantity and quality are determined). As discussed above, "market structure" refers instead to the factors determining whether a market operates competitively or otherwise, such as the number of producers (or buyers), producer behaviour, statutory monopolies, and so on.

BILATERAL MARKETS

Markets can be arranged along "mediated" or "bilateral" lines, with associated market types ranging from the centralised to the decentralised (or less organised), as summarised in Figure 2.1.2. In bilateral markets buyers and sellers trade directly, whether privately (i.e. via private "search"), bulletin boards (or websites), or facilitated by a broker (who takes a fee when the parties transact, but is otherwise not involved in the transaction). Such trades involve varying degrees of decentralisation (they might involve only the parties to the exchange or use some means to bring multiple buyers and sellers together to then engage in bilateral exchanges) and flexibility (the parties can set their own terms, do not require a standardised product, etc), but may involve higher transaction costs than other trading mechanisms because of search, contracting and other costs (such as assessing and bearing counter-party credit risk). Since prices are set privately the bilateral approach involves a risk of potential "mis-pricing" (i.e. settling on prices that are not necessarily the best achievable for either party), to the extent that seeking out the best available price involves cost. Furthermore, it typically offers no useful pricing information to third parties who might not even be aware that a trade has occurred. The form of trading will also be affected by the frequency of transactions: the higher the frequency, the more it pays to invest in lower transaction-cost mechanisms of exchange.

FIGURE 2.1.2 **Stoft (2002) Scheme of Market Types**



Arrangement	**Type of Market**				
Bilateral:	Search	Bulletin Board	Brokered		
Mediated:			Dealer	Exchange	Pool

Less organised ←→ More centralised

Source: Stoft (2002).

MEDIATED MARKETS

By contrast a mediated market involves a process of simultaneously bringing together multiple buyers and sellers and using some mechanism for determining which of them are to exchange with which others, and on what price, terms and conditions. The dealer will buy and sell from or to participants, which may require the carrying of an inventory of the product being traded. Instead of taking a broker's commission, the dealer instead tries to "buy low" and "sell high", the profit margin on trades being the "spread" (often referred to as the "bid-ask spread"). A key difference between a bilateral broker and a mediated dealer is that the dealer posts prices for buying and selling to potential or current market participants, which provides trading "immediacy" and helps third parties to "discover" and evaluate the current worth of trades to others. By the process of competition and Darwinian survival this should drive prices (and spreads) towards the collective market's assessment of where they should be (versus bilateral trades which should be more expected to reflect private assessments of worth).

EXCHANGE OR AUCTION MARKETS

Representing a more formal system of organising trades, a so-called "exchange" or "auction market" uses auctions to set the price at which trades take place. As such, this type of market signals the aggregate assessment of traders on the exchange of the traded item's worth, and diminishes the need for potentially expensive buyer and seller search. By acting as counterparty to trades, this market type relieves traders of counterparty credit risk. Through standardising the quality and/or quantity of items traded, and/or the terms and conditions of trades, they can increase the "depth" of the market (i.e. numbers of buyers and sellers seeking to trade), increase competition among both buyers and sellers, and thereby reduce the costs of trading, increase the speed at which trades can occur, and increase the "efficiency" (in the economic "social optimum" sense) of the price-setting process. Ultimately, the social desirability of the exchange market will depend upon the nature of the transactions: that is, do the savings in search costs and the benefit of more-informed price discovery outweigh costs of standardisation and administration?

ELECTRICITY POOLS

"Pools" represent a highly centralised form of trading favoured by many countries when creating markets for electricity. More than simply running auctions to set traded prices, they often involve complex optimisations to determine (for example) the least-cost means to configure an array of offers from each of a number of sellers (generators) and bids from buyers (electricity purchasers), possibly at a number of delivery points across a network (i.e. generator injection points and purchaser off-take points), that simultaneously satisfy a range of constraints to do with network security (i.e. to avoid network failures). As such they represent an attempt to bring together competition among buyers and sellers of electricity over a wide geographic area while ensuring that the technical constraints that complicate network operation, to the extent that they are binding at the relevant time, are simultaneously satisfied. While a centralised pool might be thought of as being akin to the centralised "planning" approach to decision-making discussed earlier, the extent of this is constrained by the determination of the rules by which the pool operates. Subject only to those rules each market participant then determines its own trading preferences and approach, preserving the decentralised "market-based" character of the pool.[33]

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[33] Clearly the pool rules could be so broadly defined and/or subject to the influence of (e.g.) a government minister or other form of "central planner" that this distinction begins to blur.

APPENDIX 2.2 – DECENTRALISED DECISION-MAKING AND THE NZEM

INFORMATION AND ACCOUNTABILITY

Decentralised, as opposed to centralised, decision-making has the advantages that decisions are taken by people who have the best information and who are accountable for their actions. It enables different decisions based upon different information and expectations of the future. In contrast to what happens under central planning, innovation is not limited by bureaucratic rules, and decisions are based upon various decision-makers' assessments and expectations of the future – not just those of the central planner. History, including New Zealand's electricity history, is replete with central-planner failure.

COORDINATION UNDER DECENTRALISATION

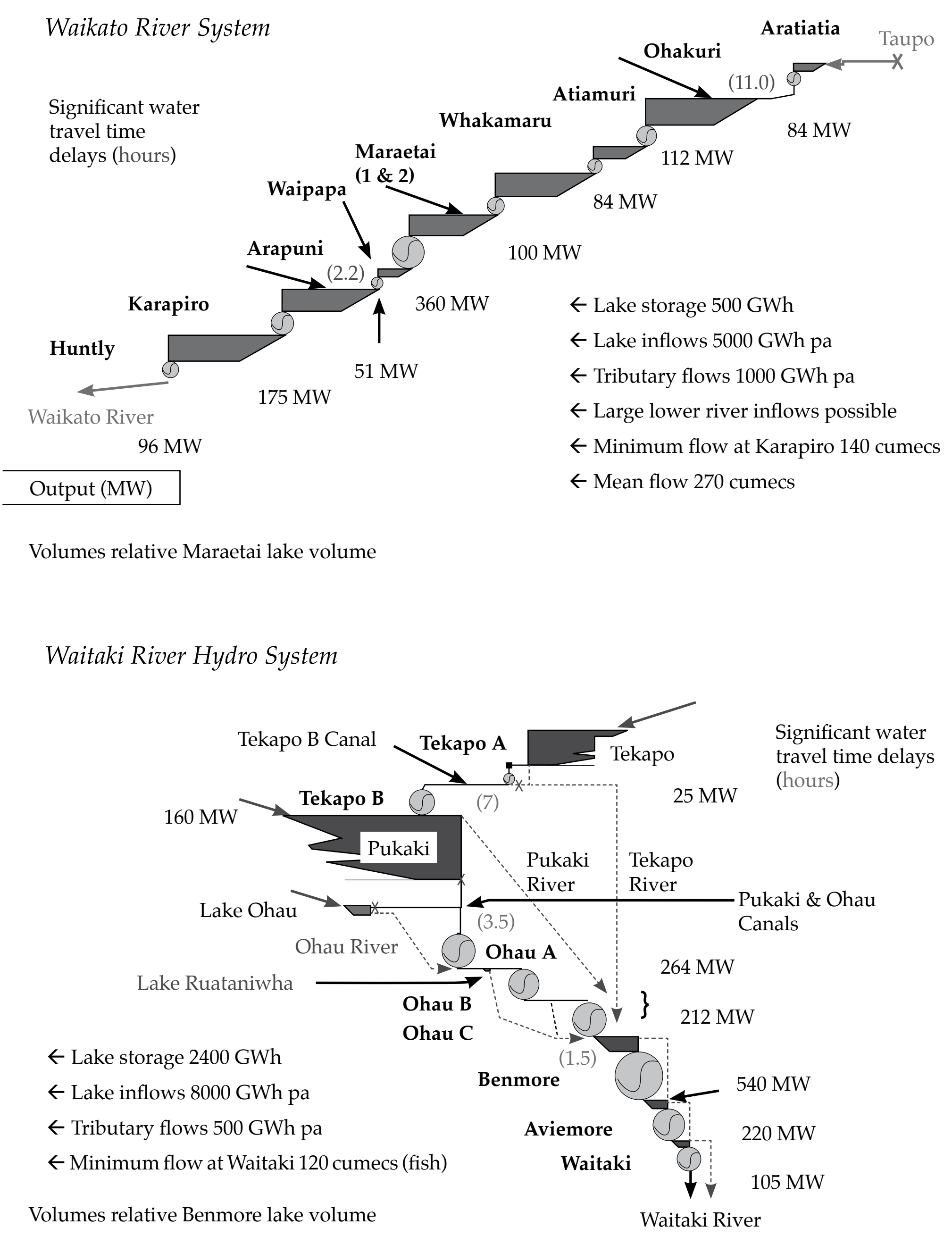
However, as with most goods and services, delivery requires coordination and none more so than electricity. The New Zealand spot wholesale electricity market coordinates electricity delivery from a number of generators and retailers at each instant in time while preserving their ability to innovate and their responsiveness to local conditions and constraints.

Separate generators manage generation on the Waikato and Waitaki rivers, and more than one thermal plant utilises the Waikato River for cooling (see Figure 2.2.1). The generators make their own plans based upon their resources – including stored energy, local resource constraints, their knowledge of the availability of thermal generation and the storage of other river systems in New Zealand, temperature and rainfall, and their expectations of demand, supply and prices. On the basis of these plans they offer generation into the market at the various nodes relating to generation on the river systems.

For offers that are accepted, these generators generate the electricity at the level of those offers under the instructions of the dispatcher. They may also supply reserve generation for frequency and voltage support, and for the management by the dispatcher of unplanned interruptions to supply, demand or transmission somewhere in the grid.

The electricity market enables individual generators and retailers to manage their own affairs in the presence of coordination that matches the production to consumption of electricity. This coordination is characteristic of all markets; the interaction of competition and coordination delivers the quantities and qualities of goods that are demanded at economic prices. For electricity, there remains controversy.

FIGURE 2.2.1 **Coordination on the Waikato and Waitaki River Systems**



Source: Robertson *et al*. (2003).

RATIONALE FOR DECENTRALISATION VERSUS CENTRALISED CONTROL

Some suggest that running the electricity sector as a centrally planned monolith would yield superior outcomes because it is under “complete” control by one “person” who has access to all relevant information about factors affecting demand and supply in each relevant sector (catchment) and who can order actions by all participants. Others suggest that the decentralised electricity generation system is less effective than the omniscient planner because forward prices at which supply would be forthcoming in future periods are not available. This is a restatement of the proposition that all would be well if there was a very liquid market in forward contracts for electricity. There is commonly no such market even in financial markets, and although markets will develop it is unlikely that they will achieve the liquidity that some hope for (although Counsell and Evans (2002) argue for a day-ahead market).

In fact, there will be local knowledge that the central planner does not have; and in the decentralised system the state of supply and demand in regions of the country are conveyed and coordinated by hydrological information, virtually all of which is public, and by electricity prices themselves (see Chapter 6). It is true that the state of other fuels (e.g. gas availability) and contracts may not be known by other entities but would be known by the central planner. There is, however, no reason to expect superior coordination by that “person”. Markets coordinate diverse expectations of the future and in electricity this includes expectations (and reactions) about demand and hydrological and thermal fuel supplies. Marrying diverse expectations is key to achieving relatively stable outcomes over time, based on better average expectations – i.e. market prices in a sense diversify expectation-error risks based on market participants’ revealed preferences (whereas the expectation-error risks of a centralised planner are decidedly undiversified). Variations in expectations and actions are valuable: one only has to contrast the outcome relating to the diverse expectations of participants relating to the 2001 water shortage to the planner’s *ad hoc* reactions to a lesser shortage in 1991. Put another way, if a single player in a decentralised system held quite wrong expectations and made (what turned out to be) erroneous choices, that player would have much less influence on the performance of the industry than would a central planner. There is no reason to suppose that the central planner has the superior expectations: history tells us otherwise. Indeed, the relative merits of the competitive, decentralised model are all-the-more apparent when the improved incentives it creates for efficiency and innovation are also considered.