NEW ZEALAND INSTITUTE FOR THE STUDY OF COMPETITION AND REGULATION INC.

Day-Ahead Electricity Markets:

Is There a Place for a Day-Ahead Market in the NZEM?

Draft v.1.

Kevin Counsell and Lewis Evans*

Abstract

In this paper we explain the operation and design of day-ahead markets in an electricity market. Day-ahead markets complement real-time markets, which must be run to ensure balance in the system, and offer a number of benefits to electricity market participants. We argue that, in the context of the New Zealand electricity market, the benefits of operating a day-ahead market are likely to outweigh the costs. We show that simple forecasts suggest day-ahead prices in New Zealand would be considerably less volatile than real-time prices. As day-ahead markets are effectively hedge markets for a short time period, the issues we raise are also important for the operation and development of other longer-term hedge markets.

* The authors acknowledge the comments of Graeme Guthrie.

1. Introduction

Electricity has an important feature that distinguishes it from many other goods: it is not economically storable. This means that electricity generated must be consumed instantaneously, as there is no possibility of storing it for consumption at a later date. The ultimate consequence of this feature is that electricity generation and load must be in balance at each instant in time. In the absence of a real-time balancing mechanism, electricity networks would be plagued by periods of insufficient generation causing potentially severe outages, wasted energy and unacceptable fluctuations in frequency and voltage. Balance is achieved in a decentralised system by the system operator running a real-time (spot) market.[1] At the same time, ancillary services and resources are managed to ensure the reliability of the system. Ancillary services include frequency, voltage and short-term reserve management. Forward markets such as day-ahead markets can be used to provide a further mechanism to facilitate electricity trading.[2] Although not an essential requirement in an electricity market (as the absence of a day-ahead market in NZEM, the New Zealand electricity market, demonstrates), day-ahead markets do supplement the running of real-time markets. In this paper we explain how day-ahead electricity markets work and how they fit with real-time markets through a 'two-settlement system' (section 2). We consider issues arising with the market design of day-ahead and real-time markets in section 3 and the benefits and costs that a day-ahead market adds to an electricity market in section 4. In section 5 we argue that the benefits may exceed the costs of a day-

[1] Real-time markets are often referred to as spot markets, as is the case in New Zealand. In this paper we will continue with the use of the term real-time markets for consistency.

[2] Markets that are even further forward than a day ahead, such as long-term bilateral hedge contracts between an electricity generator and purchaser, also play a very important role in the operation of electricity markets. The main focus in this paper is on day-ahead markets. However the operation and benefits of long-term hedge contract markets are quite similar to those of day-ahead markets, as a day-ahead market is effectively a short-term hedge market. Forward markets of different duration have different costs and benefits.

ahead market in the context of the NZEM. Section 6 provides graphical comparisons of possible day-ahead and actual real-time prices in NZEM using a simple forecasting technique and relates these to the performance of the day-ahead PJM[3] market in the Northeastern USA. Concluding comments are presented in section 7.

2. Day-Ahead Markets

A day-ahead market, as its name suggests, is a market for electricity that operates a day in advance of the actual operating day. For example, the day-ahead market operated in New York requires submissions to the market by 5am of the day before the operating day. A day-ahead market differs from the real-time market, which typically operates in half hour or hour trading periods on the actual operating day. A day-ahead market will match with each of these trading periods, so that for each trading period on the operating day both the day-ahead market and the real-time market will be run. Day-ahead markets are a type of forward market, which allows the market to be both a 'financial' market and a 'physical' market. A financial market allows participants to buy or sell power on the market, with no actual obligation to deliver the power. Any power that is not delivered will be met by a financial transfer. In contrast, a physical market requires any trading to correspond to an actual transfer of power. A day-ahead market allows both financial and physical participation, whereas a real-time market is a purely physical market, as electricity transferred instantaneously is the sole subject of the transaction.

[3] PJM operates the electricity system in all or parts of Delaware, Maryland, New Jersey, Ohio, Pennsylvania, Virginia, West Virginia and the District of Columbia.

Day-ahead markets and real-time markets are conceptually distinct and in practice should remain as two distinct markets. Cramton (2003) explains how the absence of a clear distinction can give participants an incentive for gaming. A market participant may alter its day-ahead schedule close to real-time in order to manipulate the real-time price to their advantage. The solution is to clearly separate the two markets. The price(s)[4] and quantities determined in the day-ahead market are financially binding and not linked to price(s) and quantities determined in the real-time market. The clear distinction between the day-ahead and real-time markets is known as a two-settlement system (sometimes also referred to as a multi-settlement system if there are other forward markets, such as an hour-ahead market).

In a two-settlement system, most trading will be done on the day-ahead market and the real-time market will only be used for deviations from what was transacted in the day-ahead market. As we shall explain, this result is in spite of the possibility of all electrical energy being dispatched in the real-time market. Generators and purchasers are able to submit offers and bids into the real-time market, but these are only used to settle any deviations from the committed day-ahead generation. The two-settlement system allows financial transfers to occur to settle any deviations, as outlined in the following example. Suppose a generator offers to sell 20MW of electricity in the day-ahead market at $10/MW. Suppose also that estimated day-ahead load is also 20MW. The generator's offer to produce 20MW of electricity at $10/MW will be accepted and this offer is now financially binding. Now, in the real-time market, the generator may adjust their offer

[4] There may be multiple prices determined if the market is run as a pay-as-bid auction, or only a single market-clearing price if it is a uniform-price auction. Section 3 explains these terms in more detail.

downwards, to (say) 20MW at $9/MW. Also, actual load may be only 15MW, lower than forecast in the day-ahead market. The generator is still paid for their entire day-ahead generation at the price they have already settled on (i.e. they receive $200). However, they will also buy back the extra 5MW of surplus generation at the real-time price of $9/MW (i.e. they pay $45 to buy back this electricity). Any deviations from day-ahead generation are always settled at the going real-time price. Similarly, purchasers of electricity will settle any deviations between their committed day-ahead purchases and their actual real-time purchases at the real-time price. It is useful to make the transaction more explicit. Suppose that q_{da} units are purchased (sold) in the day-ahead market at a price p_{da}, then if the participant obtains q_{rt} in real-time its total cost (revenue) will be

$$p_{da}q_{da} + p_{rt}(q_{rt} - q_{da}) = (p_{da} - p_{rt})q_{da} + p_{rt}q_{rt} \tag{1}$$

where p_{rt} is the real-time price. Thus, the amount paid (received) for the actual offtake can be viewed either as the day-ahead cost (revenue) adjusted for the discrepancy between the day-ahead and real-time quantities or the real-time cost (revenue) adjusted for the discrepancy between prices in the two markets.

By allowing deviations from day-ahead generation and load to be settled in the real-time market, the two-settlement system is ‘incentive-compatible’ (Irastorza and Fraser, 2002) in that generators and purchasers have the same incentives in real-time as if they were trading all their electricity in the real-time market and the day-ahead market did not exist. This is because a generator or purchaser of electricity will pay for, or be paid for, any deviations from electricity committed in the day-ahead market. Hence, they have an incentive to offer or bid their entire desired generation or load in the real-time market with the net effect being that the two-settlement process manages deviations. The crucial advantage of this is that regardless of what has taken place in the day-ahead market (or what mistakes may have been made), market participants will pursue the optimal strategy in the real-time market (Stoft, 2002).

Day-ahead markets are particularly prevalent in the operation of electricity markets in the U.S. For example, PJM operates both a day-ahead market and a real-time balancing market. Bids and offers are submitted into the day-ahead market and market-clearing prices for each hour of the next day are calculated.[5] The real-time market is then used to manage deviations in generation (supply) and load (demand), with market-clearing prices calculated every five minutes and integrated over each hour. In New York, the New York Independent System Operator (NYISO) runs a market similar in structure to the PJM market. Along with a real-time and day-ahead market, the NYISO also runs an hour-ahead market. In New England, the ISO has recently (from 1 March 2003) introduced a day-ahead market to supplement its existing real-time market. The new market, along with a number of other changes to the way the market system operates, are in line with a standard market design to be implemented by the Federal Energy Regulatory Commission (FERC). One of the key elements of FERC's standard market design, which establishes a standard framework for the operation of wholesale electricity markets across the U.S, is the existence of both a day-ahead and real-time market to support bilateral hedge contracts between electricity traders (Federal Energy Regulatory Commission, 2002).

[5] PJM has hour-long trading periods whereas NZEM uses half hour periods.

3. Market Design Issues

Centralised or Decentralised

Market design of day-ahead, real-time and long-term forward markets is crucial to the functioning and outcomes of the overall electricity market. A key issue that arises in electricity market design is whether a particular market should be decentralised or centralised.[6] A decentralised market mechanism is a market with no specialised institutional trading arrangement where generators and purchasers of electricity trade directly with one another through contracts. In contrast, a centralised market involves a special purpose institutional trading arrangement; such as, for electricity, with a system operator in the role of a central auctioneer, who coordinates generators' and purchasers' offers and bids to determine the market price and quantity of electricity traded. The desirable choice of decentralised or centralised trading arrangement varies with the characteristics of the market. For electricity, as Stoft (2002, p.230) notes: "[i]t is generally agreed that [real-time] operation should be centralized and the forward markets beyond a week should be bilateral and decentralized." Why might this be the case? Drawing and expanding on the ideas of Evans and Mellsop (2003), there are two aspects that are important to consider in the debate over centralised or decentralised markets.

The first of these is the level of transaction costs. The centralised coordination of buyers and sellers is difficult when it entails relatively high transaction costs. For example, if there are a large number of buyers and sellers that are geographically scattered with

[6] Not to be confused with participants' decentralised decision-making. Both centralised and decentralised market mechanisms as we define them allow participants to act independently.

limited means to communicate on a mass scale[7], and heterogeneous products of varying quality, the costs of operating a centralised market may be high. In this case, a decentralised market where buyers and sellers instigate bilateral transactions with each other is likely to be more cost effective. In an electricity market, transaction costs are lowered due to the homogeneity of the product, but in forward electricity markets products such as long-term hedge contracts will not be homogenous, as they will be specified for varying lengths and locations. If, for example, for a six-month-ahead electricity market, it is unlikely that there will be enough generators or purchasers requiring exactly six-month contracts to justify a centralised market. Hence the transaction cost savings from centralising such a market are unlikely to outweigh the costs. In this case the costs from operating a decentralised market may be lower, in which case it would be preferable to let generators and purchasers instigate transactions amongst themselves for their desired contract length.

As electricity markets approach real-time, the product becomes more homogenous in that more participants will be attracted to it, and the transaction costs of operating a centralised market decrease. In a day-ahead market, for example, the product is the same for all market participants: electricity generated or consumed on the following day, and virtually all participants will have an interest in it. There will be higher demand for a centrally coordinated day-ahead market than (say) a six-month-ahead market as relatively more suppliers and demanders will be interested in participation. As mentioned, the demand for long-term contracts will vary as to term matching the risk profiles and appetite for risk of the various participants in the industry. In short, a centralised market

[7] Electronic communication possibilities have reduced this cost.

may lower transaction costs and be more cost effective than a decentralised market for the running of day-ahead and real-time markets.

The other aspect argued by Evans and Mellsop is that information exchange in a market can be welfare enhancing. We suggest that centralised markets will promote more information exchange than decentralised ones. The argument is drawn from auction theory. Auctions are used because a seller (or buyer in the case of electricity) faces uncertainty in the value each buyer (seller) attaches to the item. Values may be private or common, or some combination of the two. Private values are where a bidder knows their personal value of the item only (e.g. the marginal cost of generation or the value of demand), whereas with common values (the price of electricity) the value is derived from the uses of the object that affect all potential market participants and so is relevant to all bidders. With common values, however, each bidder will hold their own, private, estimate of the common value and these may differ. In electricity markets, the common value is the price of electricity that affects all participants. Furthermore, generators and purchasers have imperfect information as to what that price may be. Their private views about the common value are expressed in their bids and offers in the real-time market and their willingness to pay the prices of long-term contracts.

Auctions with elements of common values are subject to the concept of the winner’s curse in which the winner expects, with good reason, that it has over-estimated (if a purchaser) the eventual price. In a pay-as-bid electricity auction the winner’s curse reflects the fact that in order for a generator to be scheduled for dispatch, they are likely to have underestimated the market-clearing price. Hence that generator is likely to be paid less for the electricity than it could have potentially made. Knowing about the winner's curse induces generators to submit higher offers to avoid undervaluing electricity and making less profit. The winner's curse does not arise in uniform-price auctions of the sort used in the NZEM.[8]

The value of a forward market for electricity is that it reveals information which helps solve this problem. Market participants base their bid and offer decisions in a forward market on their current values and expectations about the future. As Evans and Mellsop show, this extra information provides market participants with more knowledge on common values, which weakens the winner's curse and leads to more aggressive (i.e. lower) offers. Furthermore, a centralised forward market will reveal more information than a decentralised one, as it reveals the outcomes of bids and offers to all participants as opposed to only those engaged in each bilateral trade.[9] Hence a centralised market may be more effective at mitigating the winner's curse than a decentralised market.

In summary, markets such as day-ahead markets that are close to real-time will have a homogenous product and higher demand than further forward markets. Hence the benefit of lower transaction costs in centralised markets is likely to be relatively significant. Day-ahead markets also reveal information, which weakens the problem of the winner's curse. Centralised markets will reconcile the information of a broader range of participants than

[8] See below and Counsell (2003) for further explanation and discussion of uniform-price and pay-as-bid auctions. The winner's curse is likely to be more prevalent in long-term electricity transactions that are infrequent than it is in repeated high-frequency transactions.
[9] In an English ascending open outcry auction all the relevant bids are revealed. See Krishna (2002, p.90).

would decentralised ones. These arguments help enlighten the above quote by Stoft and could suggest why centralised are more prevalent than decentralised markets in operating day-ahead and real-time electricity markets around the world.

Uniform-Price or Pay-As-Bid Auctions

The other main design issue, particularly relevant to the two-settlement system, is the auction format used in a centralised electricity market. Electricity markets are effectively run as auctions, with generators and purchasers able to submit offers and bids for how much electricity they wish to sell or buy and at what price. The two common auction formats are uniform-price and pay-as-bid auctions.[10] In a uniform-price auction, the market-clearing price is determined and market participants will all be paid (or pay) the same market-clearing price for electricity sold (or bought). In contrast, in a pay-as-bid auction every participant will be paid (or pay) the actual price they offer (bid) on any electricity sold (or bought). Uniform-price auctions are more common in electricity markets, and are used in both day-ahead and real-time markets in U.S. electricity markets and in the real-time market in the NZEM. Pay-as-bid real-time electricity auctions are rare, although the New Electricity Trading Arrangements recently implemented in the U.K attempts a pay-as-bid real-time balancing market.

In a centralised real-time market, a uniform-price auction may enable better price discovery than pay-as-bid. In a pay-as-bid auction, generators aim to get the most out of the market by estimating the market-clearing price and offering at that price. In this way, they avoid having to suffer by being paid for an offer lower than the clearing price, when

[10] See Counsell (2003) for a more detailed comparison of uniform-price and pay-as-bid auction formats.

they could have bid higher at, or close to, the clearing price and still have been scheduled for dispatch. The problem is that if all generators are offering at what they believe the market-clearing price will be, the system operator does not have the information available to schedule the most efficient generator. Conversely, in a competitive uniform-price auction, generators have an incentive to bid at their marginal cost. So by operating a uniform-price auction in real-time, the system operator has the relevant information to obtain the least cost generation to meet any deviations from the day-ahead generation and load, and is provided with an order for dispatch. In short, the uniform-price auction discovers the least cost supply schedule and price but the pay-as-bid auction only discovers the price.

However, a uniform-price auction can be affected by gaming from generators that hold sufficient market power. In non-competitive situations, a generator may push up the price on an offer that they know will set the market-clearing price, in order to obtain higher profits on units that do not set the market-clearing price at lower offers. A pay-as-bid auction may limit this incentive for a generator to exercise market power, although larger generators can have an advantage in a pay-as-bid auction as they may have more resources available to forecast the market-clearing price than smaller bidders.

Although a pay-as-bid day-ahead market does not find the least cost dispatch schedule, this is irrelevant for the operation of a day-ahead market. The system operator only requires a least cost dispatch schedule when physical dispatch occurs, which is in real-time. A uniform-price auction in the real-time market will allow that to be found. Hence, it is possible that a combination of a pay-as-bid day-ahead market and a uniform-price real-time market may significantly improve price discovery.

4. Benefits of Day-Ahead Markets

Although day-ahead markets are not essential in running an electricity market, they do provide a number of benefits to generators and purchasers of electricity. Irastorza and Fraser (2002) classified the main potential benefits of day-ahead markets into five categories, which we will summarise and elaborate here.

Reliability

The first of these benefits is the increase in reliability. Day-ahead markets allow the generators to lock in generation a day before it is required. This ensures enough generation is available in advance to meet the day's requirements and provides certainty for generators. Generators will know in advance whether a particular unit will be run and how long it is expected to be run for. Furthermore, day-ahead markets protect the demand side in terms of ensuring the reliability of supply and assisting in load management. A day-ahead market will provide more certainty in the scheduling of interruptible load (i.e. load that can be disconnected to provide instantaneous reserve when load exceeds generation).

Demand-Side Participation

The second benefit is that a day-ahead market is likely to promote increased demand-side participation from purchasers of electricity. The lack of active demand-side participation has been blamed as the root of many problems that exist in electricity markets (Fraser, 2001). Recent research suggests that improving demand-side participation in electricity markets will provide significant benefits. For example, the Peak Load Management Alliance (2002) in the U.S classifies the benefits into seven categories: enhanced system reliability, cost reduction, improved market efficiency, better risk management, environmental benefits, customer service improvements and market power mitigation. By giving the demand-side an incentive to lock in prices and quantities ahead of real-time and reduce exposure to volatile real-time prices, purchasers will be more willing to participate in the market. A day-ahead market creates such an incentive. Purchasers in a day-ahead market know in advance the price they will pay for their electricity. This also allows them to alter their consumption and buy back or sell power on the real-time market if it is in their interest to do so.

Unit-Commitment

Thirdly, day-ahead markets help solve the problem of unit-commitment. This is the problem of whether to commit a unit to generation when that unit takes a long time to start up. This is more prevalent with thermal generation units (such as steam turbines that burn coal), which typically take a long time to start-up,[11] whereas hydro-generation units can start quite quickly. The problem arises for generators who may be unsure whether to commit a particular unit to generation, as it may not be cost effective to do so. By creating a day-ahead market, there is adequate time to commit generation and start up

[11] Not all thermal generation units are slow to start. For example, gas turbines typically have very fast start-up times.

slow start units. Generators are able to use the price signals provided by the day-ahead market to commit units knowing it will be cost effective to do so.

Price Uncertainty

The fourth benefit identified by Irastorza and Fraser of operating a day-ahead market is that the impact of uncertainty in real-time market prices is reduced. Participants in a day-ahead market are effectively taking out a day-long hedge contract against volatile prices in the real-time market. With the two-settlement system in place between day-ahead and real-time markets, generators and purchasers know for certain that any quantity transacted on the day-ahead market will not be subject to real-time prices. Such prices are only charged when there are deviations from scheduled day-ahead load or generation.

Evidence from overseas electricity markets such as California and New York suggests that only a small proportion of electricity is actually traded in the real-time market (Irastorza and Fraser, 2002, p.29). The majority is traded through a day-ahead market or forward bilateral hedge contracts. In the absence of a day-ahead market a generator may hedge (say) 80 percent of its generation in forward contracts, leaving 20 percent of its generation as ‘at-risk’, which is exposed to volatile real-time prices. Due to changing supply and demand conditions (for example, changing weather conditions in a hydro-generation system), a generator can obviously not hedge 100 percent of their generation in forward contracts, or they run a significant risk of over or under supplying their hedges on the real-time market. However, a day-ahead market reduces the margin of at-risk generation, leaving much less than 20 percent subject to volatile real-time prices.

Similarly, a purchaser of electricity may have a large proportion of their electricity purchases in long-term hedge contracts, but this still leaves a small amount at risk to volatile real-time prices. Again, a day-ahead market reduces this amount of at-risk generation. Although the level of day-ahead prices is likely to be similar to the level of real-time prices,[12] and there are always going to be deviations that need to be managed by a real-time market, the combination of forward bilateral hedge contracts and a day-ahead market will substantially reduce the impact of volatile real-time prices on market participants.

Gaming

Finally, a day-ahead market is beneficial in that it can reduce gaming incentives by participants in the real-time market. As already mentioned, a pay-as-bid auction format may reduce any gaming opportunities that can occur in a uniform-price auction. In addition, a day-ahead market in itself, regardless of its format, can mitigate incentives for gaming the real-time market. In a uniform-price real-time market a generator may attempt to game the market by withholding generation close to real time. Obtaining alternative generation is likely to push up the market-clearing price that a generator receives on other units of electricity that it is scheduled to generate. In a day-ahead market, generators' prices are locked in at the day-ahead price, so they will not gain by seeking to effect the real-time price and thus have no incentive to do so. The real-time market is only used to manage deviations from day-ahead load and generation. Hence generators are unable to benefit from high prices in the real-time market because their

[12] Irastorza and Fraser (2002, p.31) show that mean prices for day-ahead and real-time markets in New York are very similar. However, the standard deviation of prices is considerable higher in the real-time market.

prices have already been determined in the day-ahead market. This is effectively what forward bilateral hedge contracts of any duration also do. By locking in an agreed price between generator and purchaser well in advance of the actual trading period, generators and purchasers have no incentive to manipulate the real-time price.

Michaels (2003) has argued that market power can be given effect by trading in both the real-time and day-ahead markets. He argues that purchasers exploited market power in the California market, leading up to the crisis in that market. However, his argument rests on the facts that California used a uniform-price auction for its day-ahead market and virtual bidding was prohibited. Further details are provided in the appendix.

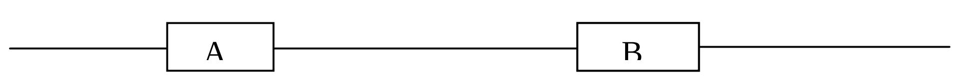
Transactions and Markets at Different Nodes

To this point we have assumed that day-ahead and real-time transactions take place at exactly the same nodes of the grid. But this need not be the case and in this section we explore the implications of day-ahead transactions taking place at fewer nodes than do real-time transactions. Because real-time transactions entail the actual delivery of electricity the nodes at which these transactions occur must at least include the nodes where day-ahead transactions take place.[13]

[13] Further, as we explain below, real-time prices mirror marginal losses in the network, and hence real-time pricing is an economically efficient way to price transmission losses across the network between transaction points.

The day-ahead pay-as-bid market requires participants on the demand and supply side of the market for the market to exist and yield committed prices and quantities.[14] Thus day-ahead markets are more demanding of active participation than is the real-time market in which prices are the solution to bids and offers for energy in relation to generation and consumption in real time and which reflect electricity flows throughout the grid. For example, in the real-time market a node with a solitary offeror and no bidder will have a price, a situation that could not occur in the day-ahead market. The real-time price arises because the demands of bidders at other nodes will be reflected in the flows of the network and therefore in the supplies, demand and price at that (or any) node.[15] Thus depth of the market at particular nodes is not that important in real-time transactions, unless network constraints arise that are sufficiently severe and long lasting to restrict electricity flows between nodes and yield pockets (groups of nodes) where a participant has market power.[16] In short, because price discovery in day-ahead markets will be improved by greater participation it is useful to consider the implications of having fewer nodes with day-ahead markets than real-time transactions. With fewer day-ahead-market nodes there is likely to be thicker markets – more participation - at these nodes.

Consider the following schematic description of two nodes



[14] Note that some of these participants may be 'virtual' bidders or offerors in that they bid or offer notional quantities and are simply trading on the difference between the real-time and day-ahead prices.
[15] Economists would describe the outcome of the real-time market-pricing model in New Zealand (SPD) as the fixed point of a general equilibrium model of the network where transport costs (losses) and constraints are recognised and where markets occur at the nodes for the homogeneous good electrical energy.
[16] See Guthrie and Videbeck (2003), who suggest that the New Zealand real-time market shows little evidence of market power.

where node A has a real-time and day-ahead market and B has only a real-time market. We first consider a participant interested in physical delivery at A. Applying our earlier approach, suppose that q_{da}^{A} units are purchased in the day-ahead market at p_{da}^{A}, then if the participant obtains q_{rt}^{A} in real-time it will cost

$$p_{da}^{A}q_{da}^{A} + p_{rt}^{A}(q_{rt}^{A} - q_{da}^{A}) = (p_{da}^{A} - p_{rt}^{A})q_{da}^{A} + p_{rt}^{A}q_{rt}^{A}$$

where p_{rt}^{A} is the real time price. Thus, the amount paid for the actual offtake at A can be viewed as the real-time price and quantity adjusted for the discrepancy between the day-ahead and real-time prices.[17]

Now consider a participant that anticipates it would like to take off q^{B} from node B but acknowledges its real-time take off q_{rt}^{B} may differ somewhat. If the participant relies on the real-time market only it will bid q^{B}, take off q_{rt}^{b} and pay $p_{rt}^{B}q_{rt}^{B}$, being fully exposed to the real-time price at B. However, the participant could utilise the day-ahead market at A. Suppose it purchased $q^{B} = q_{da}^{B}$ in that market but took no electrical energy at that node, then the final cost of the transaction for offtake at B would be

$$p_{da}^{A}q_{da}^{A} + p_{rt}^{A}(0 - q_{da}^{A}) + p_{rt}^{B}q_{rt}^{B} = (p_{da}^{A} - p_{rt}^{A})q_{da}^{A} + p_{rt}^{B}q_{rt}^{B}$$

which is the real-time cost at B adjusted by an amount for the difference between the day-ahead price at A and the real-time price at A. For the particular case of $q_{da}^{A} = q_{rt}^{B}$ the final cost of the transaction is

$$(p_{da}^{A} - (p_{rt}^{A} - p_{rt}^{B}))q_{rt}^{B}$$

[17] As we indicated earlier, if the bid quantity is the same as the real-time quantity the real-time price is irrelevant to the cost of the purchase.

which is the quantity obtained in real-time times the day-ahead price adjusted for the differential between the real-time prices of nodes A and B. Thus, the purchaser at B can obtain its electricity at the day-ahead price at node A, but adjusted for the price differential between nodes A and B. We conclude that if prices are generally very similar at a set of nodes and a day-ahead market exists at one of these nodes that the day-ahead market can provide a day-ahead hedge against the price level (or basis) of the market virtually as if transactions were carried out at the node with the day-ahead market. The question remains: what is the meaning of 'similar'?

Notice that p_{rt}^A may differ from p_{rt}^B due to both predictable elements – these would include average losses between the two nodes – which we describe as $E(p_{rt}^A \mid p_{rt}^B)$, and unpredictable elements – that we denote ε_{rt} - such as arise with short term variations due to volatility in the network, climate and demand more generally. The predictable differences would also arise between day-ahead markets at A and B and do not represent a significant extra difficulty in not having a day-ahead market at B.[18] Indeed, it must be expected that it will be more costly to purchase at B if losses are generally incurred in transferring electricity between A and B. However, variation in the unpredictable element does represent a major problem in having a missing day-ahead market at B for if this variation is large there is such separation between A and B that neither node has much useful information about the other. Thus by 'similar' we mean very low variation in ε_{rt} in

$$p_{rt}^A = E(p_{rt}^A \mid p_{rt}^B) + \varepsilon_{rt}.$$

[18] Although data yielded by a day-ahead market at B may assist accurate estimation of $E(p_{rt}^A \mid p_{rt}^B)$.

Guthrie and Videbeck (2003) approach the issue by evaluating the geographic structure of the New Zealand spot market: NZEM. In our terminology, they suggest that prices are similar if they lie in one market and they suggest that prices lie in one market if a single common factor explains virtually all the variation of prices in that market.[19] Where an additional factor is required to explain price variation there may be some market separation. Guthrie and Videbeck (2003) conclude that although one factor explains a very large fraction of the variation across the New Zealand market there is some evidence of two markets, although the quantitative implications of the separation are very small.[20] In terms of the foregoing model the work suggests that the variation in ε_{rt} is very small if one electricity market is assumed across New Zealand and that it is negligible if two factors are admitted. The second factor they identify as suggesting some separation depicts variously limited separation over the HVDC link or at the Tokaanu node. On the basis of Guthrie and Videbeck's primary analysis of New Zealand prices there would be negligible benefit in day-ahead markets at more than three nodes: one in the South Island, one in the lower North Island and the third in the upper North Island.

Transactions between nodes can be facilitated by financial transmission rights.[21] These utilise loss and constraint rentals[22] to provide surety in internodal prices. For their holders

[19] Guthrie and Videbeck (2003) place this definition in the context of the debate about differences and similarities between anti-trust and economic markets.
[20] For example, their work suggests that including two factors explains 98% of the variation of prices across 8 nodes of the New Zealand grid. To place this in perspective, if the explanation was 100% then the variation in ε_{rt} would be zero and $p^a_{rt} = E(p^a_{rt} \mid p^b_{rt})$.
[21] See www.ftr.co.nz, the website on financial transmission rights of Transpower New Zealand Limited, and Evans and Meade (2001).

they reduce the volatility of internodal prices and offer insurance against trend increases in losses. Their duration is typically a month or more and hence they may still be useful in the presence of day-ahead markets, although these markets take out a lot of the short-term volatility.[23] In the presence of day-ahead markets financial transmission rights may have a role in reducing volatility between the day-ahead-market and other nodes: in our example between p_{rt}^{A} and p_{rt}^{B}. The primary analysis of Guthrie and Videbeck *op cit* suggests that with two strategically placed day-ahead markets internodal volatility on a daily basis would be very small. If so, it would be in essence the role of financial transmission rights to limit the volatility over longer periods and perhaps between the more disconnected nodes. Financial transmission rights could be based on the day-ahead prices.

The PJM market is illustrative.[24] It has close to 3000 nodes at each of which are posted day-ahead and real-time prices. They also calculate and post day-ahead and real-time prices for collections of nodes grouped in various ways. The financial transmission rights of PJM entitle the holder to receive compensation for congestion charges when the grid is congested in the day-ahead market and day-ahead real-time dispatch occurs to relieve that congestion. They are based on hourly day-ahead energy price differences across nodes.

[22] These rentals arise because losses increase at an increasing rate with energy throughput and prices are set at marginal losses: see Figure 1 below, where they are given by the area between the price and the marginal loss function.
[23] See Section 6.
[24] See "PJM eFTR Users Guide". www.pjm.com

5. Is There Scope for a Day-Ahead Market in New Zealand?

When the New Zealand electricity market (NZEM) began in October 1996 it included a day-ahead market. However this market was not used and was subsequently abandoned. One possible reason for its demise is that there was very little volatility in prices in the early period of the market, meaning there was little need to hedge against volatile prices through a day-ahead market. Table 1 below shows the mean and standard deviation of final spot prices in the NZEM, for each year from 1997 to 2002. The data consists of final prices in each of the 48 half-hour trading periods for each day at the Haywards node. The standard deviation in 1997 shows that prices in that year were considerable less volatile than in subsequent years (even excluding the outlier in 2001 caused by exceptionally dry conditions). This lack of volatility in the early period of the market may go some way towards explaining the demise of the day-ahead market.

Table 1: Mean and standard deviation of final daily prices at Haywards node

Year	**Mean ($/MWh)**	**Standard Deviation ($/MWh)**
1997	45.01	14.17
1998	34.80	26.08
1999	33.39	24.83
2000	32.49	28.59
2001	79.85	84.20
2002	40.16	29.32

Another reason for the absence of interest could be that, at the outset of the market ECNZ was required to have a large proportion of its generation in long-term hedges. In 1995, ECNZ and the Government signed a Memorandum of Understanding (MOU) that allowed the formation of Contact Energy from ECNZ's assets. The MOU also required that ECNZ offer a specified proportion of their generation in long-term hedge contracts.

In 1997 this proportion was 87 percent, dropping to 70 percent in 1998 and lower proportions in later years. With only a small proportion of generation remaining at risk to volatile spot prices, ECNZ would have had no need to further reduce the margin of at-risk generation through a day-ahead market.

A further possible reason is that, up until April 1999, the electricity industry was a duopoly. Initially, the generators were ECNZ and Contact Energy (ECNZ was split into three competing state-owned enterprises in April 1999). With reduced competition, generators would have more certainty over dispatch. There would not be the same competitive jostling for dispatch that is more likely to occur in a more competitive market. Hence, it was perhaps the case that the generators did not need the added certainty that locking in generation in a day-ahead market would have provided and so did not require the use of this market, which when combined with low price variation[25] may have affected the demand from purchasers as well.

Although prices are now more volatile and the industry has become more competitive, there are other characteristics of the New Zealand electricity industry that would mitigate demand for a day-ahead market. With the abundance of quick-start hydro-generation units in New Zealand,[26] the problem of unit commitment is not likely to be so large. Generators can respond quickly with hydro units if they know it will be cost effective to

[25] Wolak (1998) showed that prices in the NZEM in 1996 and 1997 were relatively less variable than prices in electricity markets in other countries (for example, in England and Wales, and Victoria, Australia). One explanation he offered for this was that the market was dominated by a large SOE generator who may have pursued other objectives besides maximising profits.

[26] In a normal hydrology year, hydro generation accounts for about 63 percent of New Zealand's electricity generation, with the remainder from gas (22 percent), geothermal (7 percent), coal (4 percent) and other (3 percent) (Ministry of Economic Development, 2002).

do so. Furthermore, the issue of reliability of generation is also not likely to be a major problem in New Zealand. With hydro-generation units, changes in the real-time situation are easy to meet by quickly starting up more units to meet extra demand. This creates reliable generation in itself, without the requirement of having units locked in the day before operation.

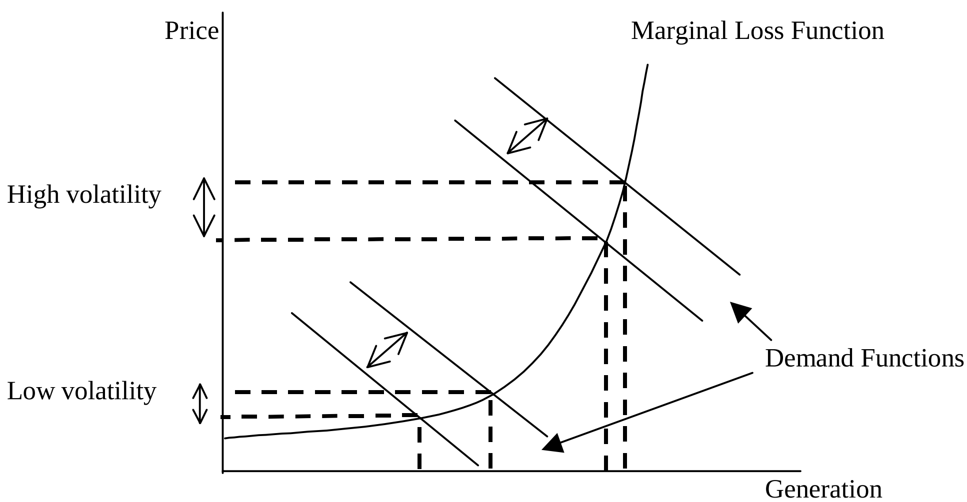
Benefits to NZEM

Nonetheless, there are some aspects of the NZEM that are likely to benefit from the operation of a day-ahead market. The first is in improving demand-side participation in the market. Currently in the NZEM, purchasers of electricity are able to submit energy offers first and effect interruptible load and reserve interruptible bids indicating their demand. However, active demand-side participation requires not only the ability for purchasers to submit bids, but also the ability to react to changes in prices. A consumer's responsiveness to price change is known as its elasticity of demand. Electricity is a commodity that typically has very inelastic demand (consumers reduce consumption only slightly in response to higher prices), particularly in the short-term. In the NZEM, consumers have limited ability to respond to price change, so their demand may be almost perfectly inelastic (represented by a vertical demand curve). The demand will be more elastic the more time there is for response and a day-ahead market will contribute to this.[27]

[27] Demand-side participation in New Zealand has been subject to a report by Demand Response (2003) and is the subject of a working group within the NZEM (Market Pricing Working Group, 2002).

The second area where a day-ahead market could bring benefits to the NZEM is in reducing the impact of volatile real-time prices. Volatile prices can occur in the NZEM due to the method of marginal-loss pricing used in the Scheduling, Pricing and Dispatch (SPD) software. Transmission losses will occur in any electricity system, as some portion of the energy will be lost as it travels through the transmission grid. These losses increase as an increasing quadratic function of the amount of electricity passing through the grid. In NZEM, prices at each node on the grid incorporate marginal losses. As a result of the quadratic nature of marginal losses, prices can be very volatile, particularly during periods where there is a large volume of electricity flowing through the grid. This is illustrated in Figure 1 below.

Figure 1: Volatile prices with a quadratic marginal loss function



When generation is low (i.e. the volume of electricity flowing through the grid is low), changes in demand do not have a large effect on prices. In contrast, when generation is high, even small changes in demand can result in highly volatile prices.

Few would argue, especially following the winter power crisis in 2001 and the prices in 2003, that prices in the real-time electricity market in New Zealand can be high and volatile. Empirical evidence supports this. For example, Table 1 above shows that the New Zealand market was subject to a much higher mean and standard deviation of prices during the dry year of 2001 when compared to the other more ‘normal’ years (in terms of weather conditions) from 1997 to 2002. Early in 2003, wholesale electricity prices again reached high levels, due to factors that include low lake inflows, uncertainty over gas supply and unanticipated economic growth. This volatility can have a significant negative impact on un-hedged demand. A day-ahead market in the NZEM would provide participants in the market with a hedge contract for electricity a day ahead of the physical transaction. Although prices in real-time may still be volatile and the basis level of prices will not be reduced, by providing market participants with price certainty the day-ahead market will reduce volatility to an extent.

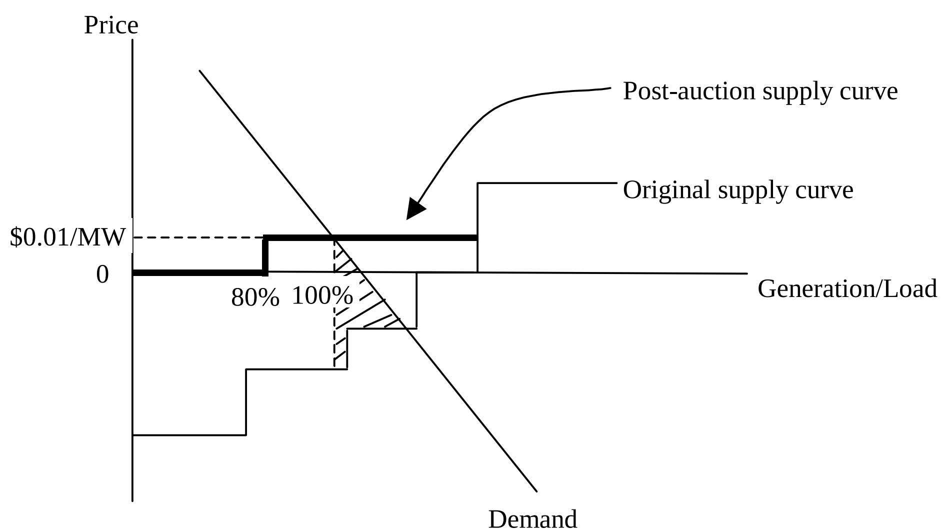
A day-ahead market may also benefit market participants by reducing incentives for gaming by generators in the real-time market. There is little evidence to suggest that gaming is occurring in the NZEM and there are reasons why any market power may be short-lived. Nonetheless, theory does suggest that with the current market design in the NZEM, there is potential that generators are able to achieve higher prices in non-competitive situations. The type of auction in the NZEM real-time market is a uniform-price auction and, as noted earlier, such auctions can be vulnerable to gaming. A day-ahead market augments the hedge positions thereby reducing the incentive for generators to seek to affect the real-time price, and so could limit any potential for market power in the NZEM.

Must-Run Generation

Another possible benefit in the New Zealand context that a day-ahead market may offer, although not one noted by Irastorza and Fraser, is in alleviating problems with must-run generation. Examples of must-run generation include hydro generation, where a generator occasionally must run to reduce high lake levels and satisfy its resource consent; thermal generation, which must run when it is costly to shut a unit down in periods of low demand; and wind generation, which by its very nature will often be running due to exogenous influences. The problem arises only in circumstances where must-run generation is so high relative to demand that it will be the only generation dispatched. It occurs rarely and in circumstances of low demand and high must-run requirements.

Generators may want to ensure that some generation is dispatched for sure and they can do this by offering in at zero or negative prices. We have already noted that plants with long start-up periods that in a real-time market must start up in trading periods preceding dispatch to the desired level, could plan for this by utilising a day-ahead market. If there are enough negative (must-run) price offers, clearing prices will be negative, which poses problems for the uniform-price auction software (SPD), which calculates the least cost dispatch schedule for the NZEM. An example of this situation is illustrated in Figure 2. Figure 2 shows a hypothetical supply curve in the form of a stack of offered generation. As there are a number of generation tranches offered in at zero or negative prices, the demand curve intersects the original supply curve at a negative price.

Figure 2: Supply and demand with a must-run dispatch auction



The short-term solution to this problem in the NZEM has been to run a must-run dispatch auction. In the first stage of this auction, generators bid for a must-run right. The quantity of must-run rights created is limited to some proportion of forecast load. The auction allows generators who are willing to pay purchasers for the ability to supply them (by offering in at negative prices) to effectively do just that, by paying for a must-run right. In the second stage, bidders who win such a right in the auction are then able to offer in to the real-time market at a price of zero (technically a price of one cent) and they are guaranteed dispatch. Non-participants and losing bidders are able to offer in at a minimum price of \$0.01/MW, but this will not necessarily ensure dispatch. The optimal least cost dispatch schedule can then be determined, as now only non-negative prices are present and a schedule of the desired order of dispatch is available to the dispatcher. Figure 2 shows the resulting supply schedule following the must-run auction. Some proportion (in this case 80 percent) of the load is covered by generators who hold must-run rights and are offered in at zero price. Generators offering in to the market at \$0.01/MW cover the remaining 20 percent of load.

Pritchard (2002) argues that problems arise in this auction if the amount of capacity offered by must-run generators is greater than actual load and if that load is uncertain. He suggests if load could be forecast perfectly, must-run rights could be auctioned off that cover all of it. However, if the allocation of rights did not fully meet actual load, the excess must be met by solving the optimal dispatch with must-run generators offered in at \$0.01/MW, as is the case in Figure 2. Pritchard shows that in this case it is often impossible to achieve such an optimum. The solution to this is to allow the must-run auction for at least as much load as there is supply and to dispatch according to the priority of the must-run offers.[28]

We tentatively suggest that the operation of a day-ahead market does not eliminate the issue but it may alleviate the need for a must-run auction. If the pay-as-bid market admits negative prices, priorities for dispatch in real-time of must-run generation may be implied

[28] We note from Figure 2 that there remains some inefficiency if the market clears at \$0.01 given by the hatched area: indeed there will be some such inefficiency at a zero price.

by the day-ahead commitments, although the SPD software still represents a constraint in dispatch levels that relate to negative prices. This topic requires further consideration.

Volatility and Discretion on a River Chain

Hydro-generation plants along a river chain are connected through their fuel source. They may be operated independently if there is separation between plants in storage, but where they are 'run-of-river' their offers (and consequently dispatch) must be coordinated. Their coordination is difficult because hydrological conditions may change abruptly[29], and for some river chains the relevant nodal prices are affected by trading period variations in the flows of adjacent connected networks. These factors make it more convenient and effective to allow generators to, in effect, dispatch their plant down river chains subject to certain restrictions: in NZEM these are that the aggregate of offers made from these plants taken collectively should not differ from that accepted by the auctioneer immediately prior to dispatch.[30] However, this mechanism poses the difficulty that the prices relating to the river-chain nodes may reflect discretionary actions taken by the generator. This can pose concerns for purchasers about the source of price variation at nodes related to river chains. A day-ahead market would significantly mitigate this concern because purchasers could have a guaranteed price and quantity at each relevant node irrespective of actions taken in real-time. To have this effect would require day-ahead markets within the set of nodes on the river chain.[31] Again this topic requires further development.

[29] This does not pose an issue if it occurs more than two hours before dispatch in the NZEM.
[30] This is a loose description of the process termed Block Dispatch in the NZEM. The generator's discretion to dispatch is limited.
[31] To completely address the river-chain issue would require a day-ahead market at each river chain node.

Administrative Cost Implications

Real-time electricity markets have the important virtue of enforcing financial backing of physical sales and purchases. This enforcement and the assurance that the other essential tasks of the market participants and those of the services suppliers – for New Zealand these are the Grid Operator, Scheduler, Dispatcher, Reconciliation Manager, Pricing Manager and Clearing Manager – are carried out with precision requires administrative resources.

There are other implications of a real-time market only system. In such a system the participants are not sure of the value of transactions until after trading. Further, because - long-term hedges aside – the real-time price applies to the entire real-time market throughput, market participants are very concerned that the processes of the real-time market work exactly as they are specified in the market rules all of the time.[32] This concern implies that the market will only be credible if its operation is demonstrably (virtually) flawless and this requires constant vigilance and rigorous enforcement of the real-time market rules.

While we have not worked through the implications in detail, we note that the presence of a day-ahead market may alter incentives in a way that may reduce these costs. Based on the evidence of existing day-ahead markets, effectively only overs and unders would be priced in the real-time market. This is likely to reduce dependence on the real-time

[32] Modern real-time markets require the acquisition, transfer and manipulation of prodigious amounts of data. While many of the operations are electronic, governance and direct human actions are critically important.

market for the prices of real-time market transactions, potentially, to a significant extent. The reduction would occur at the same time as market participants gained certainty and transparency in the bulk of their real-time market transactions via the pay-as-bid day-ahead market. Concomitantly with this there may be somewhat less need on the part of participants for the real-time market to be as ‘flawless’ as it is required to be if all short-run transactions dependent upon the prices it produces. If so administrative costs would be lower. For these reasons a day-ahead market would not be simply a cost add-on to the real-time market.

6. Price Comparisons in Day-Ahead and Real-Time Markets

It is useful to consider how day-ahead prices would compare with real-time prices if a day-ahead market were to operate in the NZEM. In this section we use a simple technique to create a series of day-ahead prices to compare with the actual real-time prices in the NZEM. The data used in this estimation are final real-time prices in each of the 48 half-hour trading periods for each day at the Haywards node, over 2001 and 2002. This data is used to estimate the following equation:

$$P_{it} = \beta_{0i} + \beta_{1i} P_{it-1} + u_{it}$$

where:

i denotes trading period $i = 1,2,\ldots, 48$,

P_{it} is the final real-time price for a trading period on day t,

P_{it-1} is the final real-time price for the same trading period on the previous day,

β_{0i} and β_{1i} are coefficients to be determined, and

u_{it} is the residual term.

The equation is estimated separately for each of 2001 and 2002. Then, using the coefficients that are determined from the equation (denoted $\hat{\beta}_{0i}$ and $\hat{\beta}_{1i}$) and the previous period prices (P_{it-1}) an estimate of the current period prices ($\hat{P}_{it}$) is calculated as:

$$\hat{P}_{it} = \hat{\beta}_{0i} + \hat{\beta}_{1i} P_{it-1}$$

This equation gives a forecast of the real-time price for a particular trading period on a particular day, based on the actual real-time prices of the day before. This is effectively what a day-ahead price is: based on the current real-time price, it is the market participant's forecast for the price at the same trading period on the following day. Although in this regression we do not capture all the effects or information that go to determining a day-ahead price, by analysing the behaviour of $\hat{P}_t$ and P_t we can gain an indication of how day-ahead prices may move relative to real-time prices in the NZEM.

The justification for this approach comes from the results of Guthrie and Videbeck (2002). They show that electricity delivered at different times of the day can be treated as different commodities, and that there may be four distinct intra-day markets operating (morning peak, mid-day, evening peak and overnight off-peak electricity). Prices within each intra-day market show significantly more correlation than between intra-day markets. Indeed, they suggest that the price for a preceding intra-day market may be quite uninformative about the price in the following adjacent intra-day market, rendering poor intra-day forecasts. They also show that a better forecast could be obtained from using the price in the same intra-day market of the previous day. For example, using the price at

4am in the overnight off-peak market to predict the price at 8am in the morning peak is likely to result in a high forecast error. However, the price at 8am on the previous day would yield a good forecast. Hence, forecasting real-time prices from the same trading period on the day before seems to be a reasonable approach and one that is suggested by the characteristics of prices.

Figures 3 and 4 below show this behaviour with forecast real-time prices one day-ahead from the regression plotted against actual real-time prices for each of 2001 and 2002. The graphs show that forecast prices from the regression are less volatile than actual real-time prices. However forecast prices still retain the general basic level of the actual prices (for example, the spike in prices in July 2001 occurs in the day-ahead market, but the volatility is less).

This is clearly shown in Table 2 below, where the mean prices for 2001 and 2002 are the same for both real-time and forecast day-ahead prices, but the standard deviations for the day-ahead prices are considerably lower. Although this is only a simple forecasting technique that we use here, the indications are that day-ahead prices would be considerably less volatile than real-time prices; in the case of 2001 and 2002, respectively, the volatility would be lower by 35 percent and 76 percent.

Table 2: Mean and standard deviation of real-time and forecast day-ahead prices, NZEM

	Mean ($/MWh)		**Standard Deviation ($/MWh)**	
Year	**Real-time Prices**	**Forecast Day-ahead Prices**	**Real-time Prices**	**Forecast Day-ahead Prices**
2001	79.85	79.85	84.20	54.58
2002	40.16	40.16	29.32	7.04

We note that this reduction in volatility does not encapsulate the benefit of a day-ahead market.[33] The ability for suppliers and demanders to respond to price signals would have some affect on the mean or average prices as well.

[33] The fact that the means are the same in the real-time and our estimated day-ahead market implies that the cost of energy will be the same.

Figure 3: Real-Time and Forecast Day-Ahead Prices, NZEM 2001

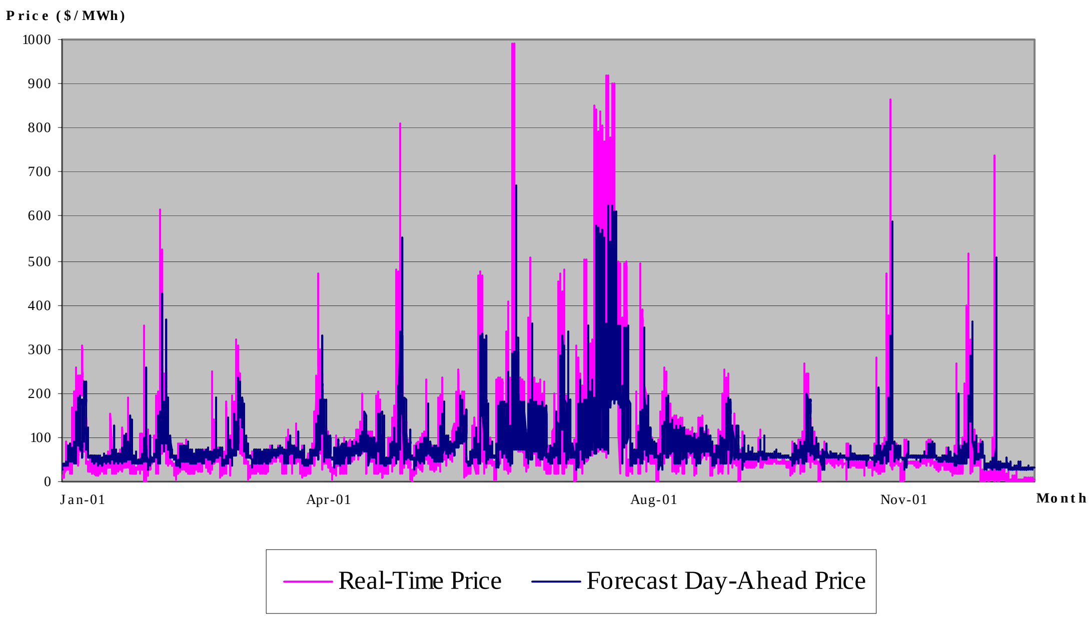
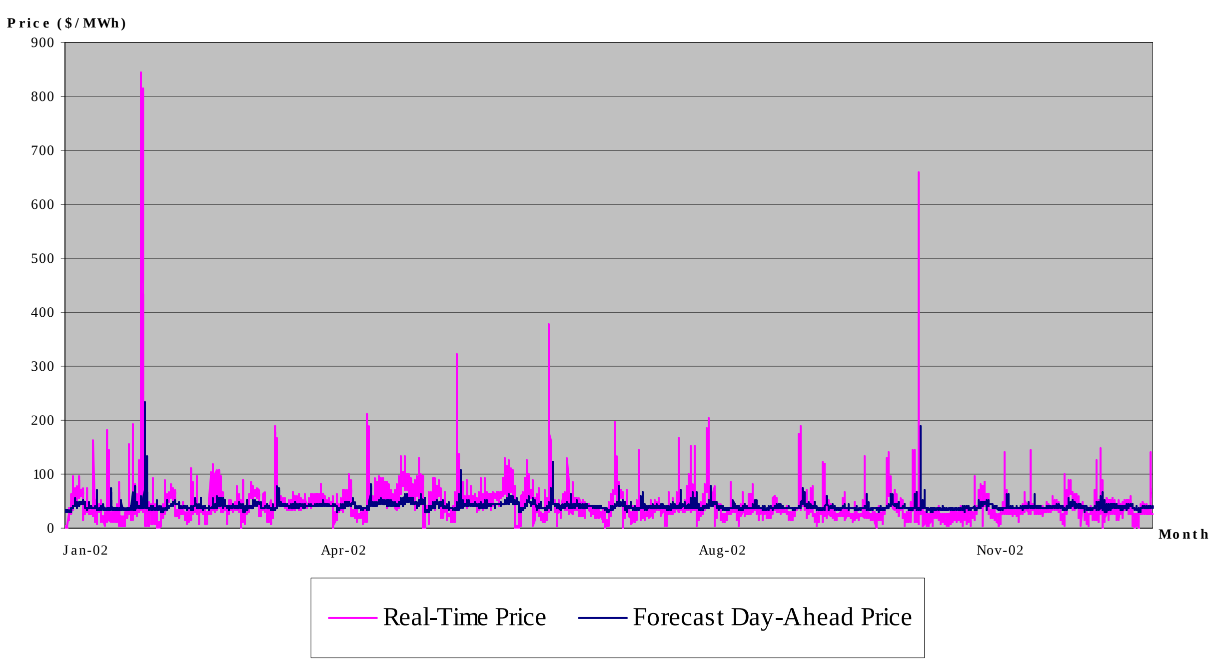


Figure 4: Real-Time and Forecast Day-Ahead Prices, NZEM 2002



The volatility reduction is further reinforced by analysing prices where both a day-ahead market and a real-time market already exist.[34] The electricity market operated by PJM in the Northeastern United States has both a day-ahead and real-time market. Figure 5 below shows how day-ahead prices are considerably less volatile than real-time prices, and illustrates the principle that day-ahead prices are effectively day-long hedge contracts. The graph shows actual load-weighted average day-ahead and real-time prices for PJM, in each of the 24 trading periods each day in April 2003, along with a hypothetical long-term hedge contract at $50/MWh. It is apparent from this graph that prices are less volatile in the PJM day-ahead market than in the real-time market. The graph also illustrates how day-ahead prices are locked in at a set level in the same way as any hedge contract is, albeit for a short time period of one day. The final real-time price may vary above or below the day-ahead price.

We use the data from PJM to gain an indication of how useful the forecasting technique we used for NZEM is as a predictor of actual day-ahead prices. As before, the real-time prices for PJM are regressed on the real-time prices for the same trading period of the previous day. The resulting equation is used to obtain a forecast of the real-time price for a particular day, based on the real-time price of the day before. The resulting series is shown in Figure 6. This shows that both actual day-ahead prices and the forecast prices from our regression move similarly and are both less volatile than actual real-time prices. This suggests that there is some merit in our estimates of the effect on volatility of a day-ahead market in New Zealand.

[34] Note that, as mentioned, we expect that the real-time prices will be affected by the presence of a day-ahead market.

Figure 5: Day-Ahead, Real-Time Prices and a Long-Term Hedge, PJM April 2003

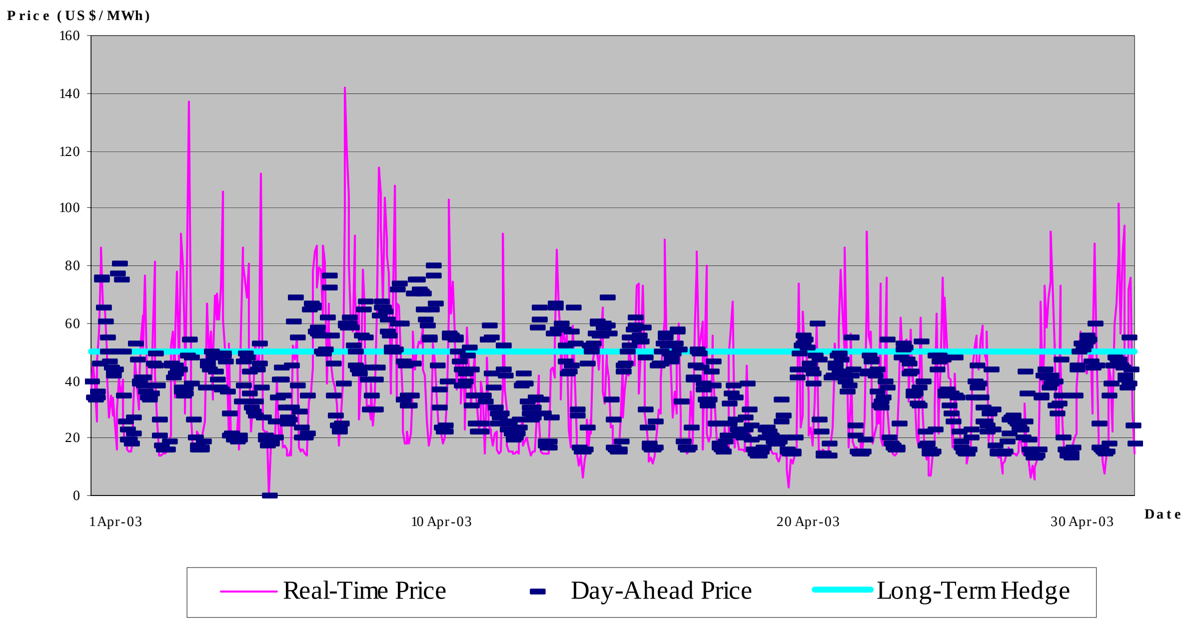


Figure 6: Day-Ahead, Real-Time and Forecast Day-Ahead Prices, PJM April 2003

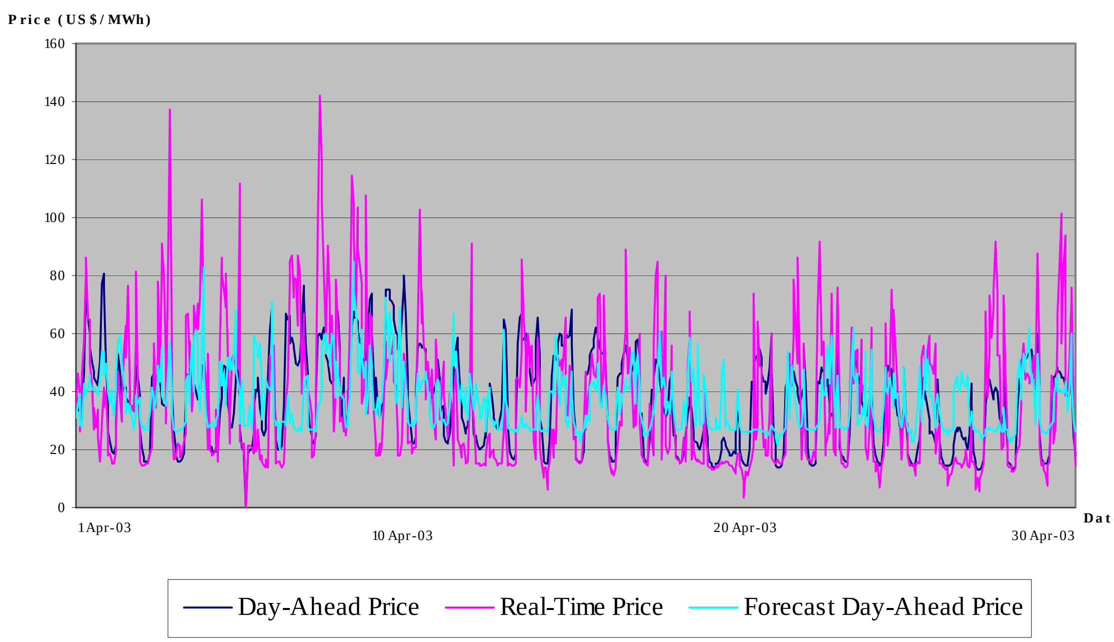


Table 3 shows further analysis of the PJM data. The mean prices in the real-time and day-ahead markets are very close, as we would expect. If prices differed significantly between these two markets, opportunities for arbitrage between the two markets would exist. It is these arbitrage opportunities that ensure the similarity between mean prices in each market. Table 3 also confirms the findings in Figures 5 and 6: that day-ahead prices are less volatile than real-time prices. The skewness and kurtosis for the PJM prices are also reported. The higher value of skewness for real-time prices shows a higher degree of right skewness for real-time prices than for day-ahead prices. The dramatic reduction in skewness shows that the high peaked prices of the real-time market generally do not occur in the day-ahead market.[35]

The peakedness of a distribution is represented by the kurtosis. The positive value for real-time prices shows that this distribution is relatively narrow with a high peak. In contrast, day-ahead prices exhibit a very flat distribution, as indicated by the negative value for kurtosis. The conclusions we can reach from the information in Table 3 is that, as well as being less volatile, day-ahead prices also exhibit a more central and flatter distribution around the mean than real-time prices.

Table 3: Mean, standard deviation, skewness and kurtosis of real-time and day-ahead prices for PJM in April 2003.

US$/MWh	**Real-time Prices**	**Day-ahead Prices**
Mean	36.59	36.99
Standard Deviation	23.39	15.90
Skewness	1.09	0.27
Kurtosis	0.99	-0.75

[35] Note that for the NZEM data, the skewness for the forecast day-ahead prices is the same as that for the actual real-time prices due to the way our forecast series is defined.

7. Conclusion

When suppliers and demanders of electricity have autonomy, real-time markets for balancing electricity generation and load are an absolute necessity. Day-ahead markets provide additional benefits to market participants when operated in conjunction with real-time markets. Such benefits include: increased reliability, promoting demand-side participation, helping solve the problem of unit commitment, reducing the impact of price uncertainty and limiting opportunities for gaming. As Irastorza and Fraser (2002) note, it is not always a foregone conclusion that these benefits will be sufficient to offset the cost of setting up and administering day-ahead markets. In New Zealand, there are some aspects of the electricity market that suggest a day-ahead market may not be useful, and others that may explain why a day-ahead market has already been tried and abandoned. Nonetheless, circumstances are different and such a market would offer benefits in some important areas of the NZEM.

The pros and cons of a day-ahead market apply to other forward markets. The longer the term of the contract the less demand there will be for the particular duration but the greater the benefit of information exchange institutions. This is a trade-off that is present in many commodity markets.

References

Counsell, K. (2003). "Uniform vs Pay-As-Bid Pricing in Multi-Unit Auctions", *mimeo*, NZ Institute for the Study of Competition and Regulation. Available: http://www.iscr.org.nz.

Cramton, P. (2003). "Electricity Market Design: The Good, the Bad, and the Ugly", *Proceedings of the 36th Annual Hawaii International Conference on System Sciences*, January 2003.

Demand Response (2003). "Exploring Our Untapped Electricity Resource: Demand-side Participation in the New Zealand Electricity Market", prepared for Energy Efficiency and Conservation Authority.

Evans, L. and R. Meade (2001). "Economic Analysis of Financial Transmission Rights (FTRs) With Specific Reference to the Transpower Proposal for New Zealand", NZ Institute for the Study of Competition and Regulation. Available: http://www.iscr.org.nz.

Evans, L. and J. Mellsop (2003). "Exchanging Price Information can be Efficient: *per se* offences should be legislated very sparingly", NZ Institute for the Study of Competition and Regulation. Available: http://www.iscr.org.nz.

Federal Energy Regulatory Commission (2002). "Standard Market Design Notice of Proposed Rulemaking: Remedying Undue Discrimination Through Open Access Transmission Service and Standard Electricity Market Design", Docket No. RM01-12-000.

Fraser, H. (2001). "The Importance of an Active Demand Side in the Electricity Industry", *The Electricity Journal*, 14(9), 52-73.

Guthrie, G. and S. Videbeck (2002). "High Frequency Electricity Spot Price Dynamics: An Intra-Day Markets Approach", NZ Institute for the Study of Competition and Regulation. Available: http://www.iscr.org.nz.

Guthrie, G. and S. Videbeck (2003). "One Market or Many? Market Integration of the NZEM." NZ Institute for the Study of Competition and Regulation.

Irastorza, V. and H. Fraser (2002). "Are ITP-Run Day-Ahead Markets Needed?", *The Electricity Journal*, 15(9), 25-33.

Krishna, V. (2002). *Auction Theory*, Academic Press.

Market Pricing Working Group (2002). "Demand Bidding and Forecasting Project: Final Report", New Zealand Electricity Market.

Michaels, R. (2003). “Watching the Watchers: Can RTO market monitors really be independent?” *Public Utilities Fortnightly*, July 15, 35-38.

Ministry of Economic Development (2002). “Electricity Supply and Demand Issues”, Media Briefing, Tuesday 24 September 2002. Available: http://www.med.govt.nz.

Peak Load Management Alliance (2002). “Demand Response: Principles for Regulatory Guidance”. Available: http://www.peaklma.com.

Pritchard, G. (2002). “The Must-Run Dispatch Auction in an Electricity Market”, *Energy Economics*, 24(3), 199-216.

Stoft, S. (2002). *Power System Economics: Designing Markets for Electricity*, New York: IEEE – Wiley Press.

Wolak, F. (1998). “Market Design and Price Behaviour in Restructured Electricity Markets: An International Comparison”, *mimeo*, Department of Economics, Stanford University.

Appendix

Gaming the Two Markets: Demand-Side Gaming of the Day-Ahead Market

We have suggested that market power concerns in a real-time market may be mitigated by the presence of a day-ahead market, but Michaels (2003) has argued that electricity purchasers with market power can game the market in the presence of the two markets. His example requires: (a) no virtual bidding and (b) a uniform-price auction in both markets.

For Michaels (2003), the cause of this problem arises from the fact that the supply curve becomes very steep when load is high, as it becomes more costly to generate the high capacity. A simple example will help illustrate how a purchaser may game the market because of this. Suppose the supply curve becomes very steep between 40 and 50 megawatts. Suppose also that the day-ahead market, in the absence of any demand-side market power, clears at $10/MWh with a load of 50MW. Hence a single purchaser of electricity will pay $500 for the hour.

Now if the purchaser had market power, and there was a uniform-price auction, they could understate their day-ahead load to 40MW and, because the supply curve is less steep at this point, the day-ahead market may clear at a significantly lower price, say $5. Hence the purchaser only pays $200 for their day-ahead contract. The extra 10MW is scheduled in the real-time market at $10, so the purchaser pays an extra $100 in real-time. The total paid by the purchaser, $300, is significantly less that the $500 they would have paid in the absence of market power. Hence the purchaser gains while the generators lose out.

In terms of our model, the general result is straightforward. In the absence of market power, the purchaser buys q_{da} in the day-ahead market at the price p_{da} and, assuming that any deviations are only due to the purchaser gaming the market, they obtain the same amount $q_{rt} (= q_{da})$ in real-time at p_{rt}. Hence the purchaser pays:

$$p_{da} q_{da} + p_{rt} (q_{rt} - q_{da}) = p_{da} q_{da} \tag{A1}$$

since $q_{rt} - q_{da} = 0$.

However, an electricity purchaser with market power will understate their demand and hence buy $\hat{q}_{da} < q_{da}$ at the price $\hat{p}_{da} < p_{da}$ in the day-ahead market. They will receive the excess in the real-time market to achieve the same total load as if there was no gaming, that is: $\hat{q}_{rt} (= q_{rt} = q_{da})$ at the price $\hat{p}_{rt} (= p_{da})$. Therefore, the buyer pays:

$$\begin{aligned} \hat{p}_{da} \hat{q}_{da} + \hat{p}_{rt} (\hat{q}_{rt} - \hat{q}_{da}) &= \hat{p}_{da} \hat{q}_{da} + p_{da} (q_{da} - \hat{q}_{da}) \\ &= \hat{p}_{da} \hat{q}_{da} + p_{da} q_{da} - p_{da} \hat{q}_{da} \\ &= (\hat{p}_{da} - p_{da}) \hat{q}_{da} + p_{da} q_{da} \end{aligned} \tag{A2}$$

Where this last term is less than $p_{da} q_{da}$ since $(\hat{p}_{da} - p_{da})$ is less than zero. The result is that the purchaser pays less when gaming the market, as equation (A2) is less than equation (A1).

Michaels (2003) notes that generators can counter demand-side gaming if 'virtual bidding' is allowed in the day-ahead market. Virtual bidding is where generators and purchasers can submit bids into the day-ahead market that are purely financial bids – that is, they will not be met by the actual delivery of power. If a generator expects the day-ahead price to be lower than the real-time price, they can bid virtual load into the day-ahead market and sell it back on the real-time market to potentially make a profit (provided the actual real-time price does turn out to be higher than the day-ahead price). Similarly the generator may do the opposite if the expected day-ahead price is higher than the expected real-time price.

In the example above, to counter the gaming by the purchaser, a generator could bid 10MW of virtual load into the day-ahead market, pushing total load up to 50MW and the price back to $10. At this clearing price the purchaser then pays $400 for their 40MW day-ahead contract. If they buy the extra 10MW on the real-time market at $10 the total they pay is $500, which is no different from when the purchaser does not game the market. Also, as the generator's load bid is virtual, they must sell the virtual load back in the real-time market.

This analysis of demand-side gaming assumes both the day-ahead and real-time markets operate as uniform-price auctions – as is the case for many U.S electricity markets. However, will the situation be any different with a pay-as-bid day-ahead market and a uniform-price real-time market? We suggest that with a pay-as-bid day-ahead market the problem of demand-side gaming may be alleviated to some extent.

The reason for this conjecture is that in a pay-as-bid market, participants aim to guess the market-clearing price and submit bids or offers close to that price. This is often viewed as a problem but in this case it can be advantageous. If all generators offer at a similar price, the supply curve will be much flatter over the entire load range. Hence a reduction in demand by an electricity purchaser may not result in significantly lower prices and so gaming may not be beneficial to the purchaser. Applying this intuition to our example is straightforward. With a uniform-price day-ahead market a reduction in load to 40MW resulted in a shift to a lower marginal cost generator and so the price fell to $5. However, with a pay-as-bid market the lower marginal cost generator would offer close to their guess of the clearing price, originally $10, and so the purchaser gets very little price decrease. The result is that there may be little incentive for demand-side gaming in a pay-as-bid day-ahead market.