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The Relationship Between Energy Spot and Futures Prices: Evidence from the Australian Electricity Market

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THE RELATIONSHIP BETWEEN ENERGY SPOT AND FUTURES PRICES: EVIDENCE FROM THE AUSTRALIAN ELECTRICITY MARKET

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This paper examines the relationship between futures and spot electricity prices for two of the Australian electricity regions in the National Electricity Market (NEM): namely, New South Wales and Victoria. A generalised autoregressive conditional heteroskedasticity (GARCH) model is used to identify the magnitude and significance of mean and volatility spillovers from the futures market to the spot market. The results indicate the presence of positive mean spillovers in the NSW market for peak and off-peak (base load) futures contracts and mean spillovers for the off-peak Victorian futures market. The large number of significant innovation and volatility spillovers between the futures and spot markets indicates the presence of strong ARCH and GARCH effects. Contrary to evidence from studies in North American electricity markets, the results also indicate that Australian electricity spot and futures prices are stationary.

INTRODUCTION

Over the past two decades an increasing number of developed and developing economies around the world have restructured their electricity markets. Starting with Chile, Argentina and the United Kingdom, and followed by the United States and most members of the European Union, these efforts have entailed a move away from the heavily-regulated publicly or privately-owned, vertically-integrated utilities of the past towards more market-based structures for electricity suppliers in the present and potentially more competitive outcomes for consumers in the future (Crow 2002).

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Australia has also been at the forefront of these efforts to introduce competition into the global power industry. Where electricity was once supplied by state government-owned entities that had never operated on a national or even a regional basis, and where interstate connections were weak and regional electricity trade limited, the market is now characterised by the separation of the generation, transmission and distribution functions by company, and by a competitive national electricity market across the majority of Australian states and territories. And for the most part, the restructuring and liberalisation of the Australian electricity market has been a resounding success. In evidence, the benefits to the economy of electricity market liberalisation amounted to AUD1.5 billion in 2000 alone, labour productivity in the electricity supply industry doubled in the last decade while capital productivity increased by ten percent, and average retail electricity prices are now more than ten percent below the levels of the early 1990s (ABARE 2002).

Nevertheless, in recent years the pace of electricity reform in Australia has slowed. The target dates for full retail competition have been delayed and each of the five National Electricity Market (NEM) members (NSW, Victoria, Queensland, South Australia and the Australian Capital Territory) are still characterised by separate transmission companies. Full privatisation has occurred only in Victoria. In South Australia private companies manage the state-owned generation, transmission and distribution companies under long-term leases; in the remaining states and territories they remain in government ownership. The dominance of the individual generating companies in each market is also high with the two largest generators accounting for seventy percent of generation in NSW, and in most other states and territories at least fifty percent. The NEM itself is not yet strongly integrated with interstate trade representing only some seven percent of total generation. During periods of peak demand, the interconnectors can become congested and the NEM separates into its regions, promoting price differences across markets and exacerbating reliability problems and the market power of regional utilities. Ongoing challenges remain in implementing efficient transmission pricing with a view to strengthening interconnection as a check on regional market power and extending retail access to all consumers.

At the same time, the establishment of electricity futures markets has paralleled these developments in deregulated spot electricity markets in Australia and elsewhere. In the United States, the New York Mercantile Exchange (NYMEX) initiated trading in electricity futures in March 1996 with power contracts at the California-Oregon Border, Palo Verde, Cinergy, Entergy, Pennsylvania/New Jersey/Maryland (PJM) and Mid-Columbia trading hubs. Though these contracts were delisted due to a lack of liquidity in February 2002, NYMEX intends to reintroduce improved exchange-traded and over-the-counter contracts on these and other commodity markets in an attempt to capture EnronOnline's OTC business following Enron's 2001 bankruptcy filing. In a similar manner in Australia, the Sydney Futures Exchange (SFE) initiated contracts based on New South Wales and Victorian base load and peak period electricity in September 1997 and base load and peak load electricity strips based on the New South Wales, Victoria, Queensland and South Australia electricity markets in July 2002.

Unfortunately, despite the key importance of market pricing within and between electricity spot and futures markets, very little empirical evidence currently exists concerning the pricing behaviour of the deregulated electricity markets in Australia or elsewhere. The short tenure of these markets is the most apparent, though not the only, reason. The few studies that do exist are then especially noteworthy. Deng (2000), for example, proposed several stochastic models of energy commodity price behaviour specifically in the context of a deregulated electricity industry. Using a number of models and assumptions [including mean-reversion, jump-diffusion and regime-switching] Deng (2000) aimed to more accurately reflect the physical characteristics of electricity in commodity spot price behaviour models as a first step in applying a real options approach to valuing physical assets in the electricity industry.

An earlier study by De Vany and Walls (1999a) took a somewhat different approach to understanding electricity pricing behaviour by examining regional power markets in the western United States for evidence of integration over the period December 1994 to April 1996. The eleven regional markets analysed included California/Oregon, Four-Corners, Central Rockies, Inland Southwest, Mead, Mid-Columbia, Midway/Sylmar, Northern California, Northwest/Northern Rockies, Palo Verde and Southern California. Using daily spot prices collected from the day ahead over-the-counter market De Vany and Walls (1999a) employed Augmented Dickey Fuller (ADF) unit root tests to first detect the presence of non-stationarity in both peak and off-peak series for all markets, with the exception of off-peak prices in the Northern California market.

De Vany and Walls (1999a) also applied cointegration analysis to test for price convergence between the markets. The results indicated a high degree of market integration between these not necessarily physically connected markets, with cointegration being found for peak prices in forty-eight of the fifty-five market pairs (87 percent) and all fifty-five market pairs for off-peak prices. De Vany and Walls (1999a) argued that the lack of cointegration in several markets was evidence of transfer constraints within some parts of the Western Electricity Grid, though on the whole the study's findings was suggestive of an efficient and stable wholesale power market. A subsequent study by Lucia and Schwartz

(2001) also used cointegration techniques, though in the context of the deregulated Norwegian electricity market and with an emphasis on the relationship between spot and derivative electricity prices.

In an alternative approach, De Vany and Walls (1999b) specified a subset of five of the eleven previously used regional markets [CA-OR-NV Border, 4-Corners, Inland Southwest, Palo Verde and Southern California] to apply vector autoregressive (VAR) modelling techniques. As in the earlier cointegration analysis, the study confirmed that both peak and off-peak spot prices for electricity contained a unit root. The results of separate variance decomposition analyses also indicated that during off-peak periods, the larger proportion of price shocks were absorbed locally and only a small proportion of the shocks propagated to other interconnected nodal markets. Conversely, during peak periods a larger proportion of shocks propagated from the originating node to more distant interconnected market nodes (De Vany and Wall 1999b: 139).

In the only known US study concerning electricity futures contracts, Emery and Liu (2002) examined the relationship between NYMEX's California-Oregon Border and Palo Verde electricity futures contracts and natural-gas futures contracts (the spark spread). After finding that both electricity and natural-gas futures were stationary in first differences, Emery and Liu (2002) concluded that electricity and natural-gas futures prices were cointegrated, though the characteristics of the relationship depended upon the nature of the regional market, and that there was no difference in sensitivity of electricity futures prices to natural-gas prices in the two service areas examined. Unfortunately, no published evidence exists concerning the pricing relationships between the Australian electricity spot and futures markets, nor within these markets alone. This lies in stark contrast to the large and ongoing amount of empirical attention directed towards spot and futures pricing relationships in other energy markets such as oil, heating oil, gasoline and natural gas [see, for instance, Hirshfeld (1983), Chen et al. (1987), Ma (1989), Cho and McDougall (1990), Bopp and Lady (1991), Deaves and Krinsky (1992), Serletis (1992; 1992b), Nainar (1993), Herbert (1995), Peroni and McNown (1998), Kellard et al. (1999) and Lim and Tamvakis (2001)]

Accordingly, the purpose of the following article is to examine the relationship between the Australian electricity spot and futures markets. As integral parts of the deregulated electricity industry, there is interest in such information for the purposes of price forecasting, hedging, speculation and estimating the value of generating assets, amongst other things. For example, the value of electricity futures markets arise from their ability to forecast spot prices at a specified future date and thus provide hedgers with a means of managing the risks associated with trade in electricity. In an efficient market the futures price will then be an optimal forecast of the spot price and the presence of such efficiency will ensure the economic benefits of deregulation. The paper itself is divided into five main areas. The second section briefly surveys the establishment and operation of the Australian electricity spot market. The third section explains the data employed in the present analysis, and the fourth section discusses the empirical methodology employed. The results are dealt with in the fifth section. The paper ends with some brief concluding remarks.

THE AUSTRALIAN ELECTRICITY SPOT MARKET

The Australian electricity spot market as epitomized by the National Electricity Market (NEM) encompasses electricity generators in the eastern state electricity markets of Australia operating as a nationally interconnected grid. The member jurisdictions of the NEM thus include the three most populous states of New South Wales (NSW) [including the Australian Capital Territory (ACT)], Victoria (VIC) and Queensland (QLD) along with South Australia (SA). The only non-state based member that currently provides output into the NEM is the Snowy Mountains Hydroelectric Scheme (SNO). The SNO is regarded as a special case owing to the complexity of arrangements underlying both its original construction and operating arrangements involving both the state governments of New South Wales and Victoria, as well as the Commonwealth (federal) government. It is intended that the island state of Tasmania will become a member of the NEM pending completion of the Basslink interconnector, which will link Tasmania's Electricity Supply Industry with that of the mainland.

The remaining Australian state of Western Australia along with the Northern Territory are unlikely to participate in the NEM in the foreseeable future due to the economic and physical unfeasibility of interconnection and transmission augmentation across such geographically dispersed and distant areas. Indeed the limitations of transfer capability imposed by geographic dispersion within the centrally coordinated and regulated NEM are one of its defining features. Queensland has two interconnectors that together can import and export 880 megawatts (MW) to and from NSW, NSW can export 850 MW to the Snowy and 3000 MW from the Snowy and Victoria can import 1500 MW from the Snowy and 250 MW from South Australia and export 1100 MW to the Snowy and 500 MW to South Australia. There is currently no direct connector between NSW and South Australia and Queensland is only connected directly to NSW.

The NEM was developed and operates under a number of legislative agreements, memorandums of understanding and protocols between the participating jurisdictions. They include a mechanism for uniformity of relevant electricity legislation across states, implementation of the National Electricity Code (NEC) and the creation of the National Electricity Code Administrator (NECA) and the National Electricity Market Management Company (NEMMCO) to control and implement the NEM. The NECA is the organisation charged with administering the NEC. This entails monitoring participant compliance with the Code and raising Code breaches with the National Electricity Tribunal (IEA: 2001: 132). Other roles of the NECA include managing changes to the NEC and establishing procedures for dispute resolution, consultative, and reporting procedures (NEMMCO, 2001: 28). The NECA also established the Reliability Panel in 1997, in order to "determine power system security and reliability standards, and monitor market reliability" (IEA: 2001: 132).

The market rules that govern the operation of the NEM are embedded in the NEC, which was developed in consultation with government, industry and consumers during the mid-1990s. NEMMCO (2001: 4) summarises the rationale for the thoroughness of the NEC:

> The rules and standards of the Code ensure that all parties seeking to be part of the electricity network should have access on a fair and reasonable basis. The Code also defines technical requirements for the electricity networks, generator plant, and customer connection equipment to ensure that electricity delivered to the customers meets prescribed standards.

The NEC required authorisation by the Australian Competition and Consumer Commission (ACCC) to be implemented, as do any changes. Born from the Hilmer microeconomic reforms in the 1990s the ACCC is the peak Australian body aimed at enforcing competition law. To this affect, the ACCC is responsible for administering the Trade Practices Act (1974), which was augmented under the National Competition Policy (NCP) reforms to facilitate access arrangements to network infrastructure and the addition of competitive neutrality provisions, which ensure there can be no discrimination between public and private service providers.

Asher (1998: 10) highlights the key change to the Trade Practices Act (1974) under the National Competition Policy reforms as "establishing a third party access regime to cover the services provided by significant infrastructure facilities" (facilities not economically feasible to duplicate and where the access arrangements would be necessary to promote effective competition in upstream or downstream markets). In addition to the administration of this role in regard to market infrastructure, the ACCC is the organisation responsible for the regulation of the transmission network component of the Australian Electricity Supply Industry.

Of the various facets this role encompasses, transmission pricing is the most prominent. This is managed by the ACCC on a revenue cap basis, in an attempt "to constrain monopoly pricing while allowing the business owners a rate of return sufficient to fund network operation and expansion" (ACCC, 2000: 8). The transmission-pricing role is carried out in conjunction with a service reliability protocol, to ensure quality of service. As noted, changes to the NEC effecting transmission or any other aspect of the market must be authorised by the ACCC. As such the ACCC is responsible for the evaluation of changes to market operations. It is the role of the National Electricity Market Management Company (NEMMCO) to implement and administer changes to market operation.

The National Electricity Market Management Company (NEMMCO) operates the wholesale market for electricity trade between generators and retailers (and also large consumers). From an operational perspective, output from generators is pooled then scheduled to meet demand. The IEA (2001: 134) summarises the core elements as follows:

> The National Electricity Market is a mandatory auction in which generators of 30 MW [megawatts] or more and wholesale market customers compete. Generators submit bids consisting of simple price-quantity pairs specifying the amount of energy they are prepared to supply at a certain price. Up to ten such pairs can be submitted per day. In principle, these bids are firm and can only be altered under certain conditions. Generator bids are used to construct a merit order of generation. Customer bids are used to construct a demand schedule. Dispatch minimises the cost of meeting the actual electricity demand, taking into account transmission constraints for each of the five regions in which the market is divided…There are no capacity payments or any other capacity mechanisms.

The two key aspects required for the pool to operate are a centrally coordinated dispatch mechanism and operation of the 'spot market' process. As the market operator, NEMMCO coordinates dispatch to "balance electricity supply and demand requirements" (NEMMCO, 2001: 3), which is required because of the instantaneous nature of electricity, and the spot price is then "the clearing price [that] matches supply with demand" (NEMMCO, 2001: 3).

The pool rules dictate that generators in the NEM with a capacity greater than 30MW are required to submit bidding schedules (prices for supplying different levels of generation) to NEMMCO on a day before basis. Separate capacity schedules are submitted for each of the 48 half-hour periods of the day. As a result, the industry supply curve (also called a bid stack) may be segmented to a maximum extent of ten times the number of generators bidding into the pool. NEMMCO determines prices every five minutes on a real time basis. This is achieved by matching expected demand in the next five minutes against the bid stack for that half-hour period. The price offered by the last generator to be dispatched (plant are dispatched on a least-cost basis) to meet total demand sets the five-minute price. The price for the half-hour trading period (or pool price) is the time-weighted average of the six five-minute periods comprising the half-hour trading period. This is the price generators receive for the actual electricity they dispatch into the pool, and is the price market customers pay to receive generation in that half hour period.

<TABLE I HERE>

An illustration of spot market pricing in the NEM is drawn from NEMMCO (2000). Table 1 contains offer prices for six generators (in megawatt hours) and demand information (in megawatts) for the six five-minute dispatch periods in the 12:30 trading interval. Assuming each of these generators has 100 MW (megawatts) of capacity, Figure 1 graphically analyses the least cost dispatch for these five-minute intervals. For example, at 12:05 total demand is 290 MW and to meet this demand the full capacity of the lowest priced generators 1 ($32 MWh) and 2 ($33 MWh) and most of the capacity of generator 3 ($35 MWh) is required. The marginal price for this five-minute interval is then $35 MWh. This information, along with the remaining five-minute intervals until 12:30, is tabulated in Table 2, which shows the marginal price for each five-minute interval as a result of the plant dispatch mix, which is primarily dependant on the level of demand. The pool price for the 12:30 trading interval is the average of these six five-minute marginal prices.

<TABLE II HERE>

The spot pricing procedure, while bringing balance between supply and demand, can expose participants to significant variation. This is owing to the dependence of the pool process on generator bidding strategies [for instance, Brennan et al. (1998) highlight the potential for holders of large generating portfolios to bid non-competitively in order to exercise market power] and the impact of the complex interaction of supply and demand factors on pricing. As such the spot price can be volatile, leading to large financial exposure. The occurrence of various phenomenon in the NEM have seen instances of high spot prices, and in some cases the maximum price cap for the NEM (Value of Lost Load) has been triggered.

<FIGURE I HERE>

Events in the past, which have had a tendency to drive NEM prices toward the upper end of the price spectrum, are of three types. First, prices can increase dramatically when a generation plant ‘trips’ or ‘falls over’, rendering it inoperable and forcing the plant’s contributed capacity to be removed from the bid stack. This is particularly the case if the plant provides base load output. Secondly, abnormal environmental temperatures drive demand up as customers increase demand for cooling or heating technology. Higher demand requires more generation to balance the system, which means plant bidding in at a higher price level on the least-cost merit order are sequentially dispatched to meet the additional demand. Third, technical constraints or faults with the systems design can also lead to higher prices. These three instances combined to cause an electricity supply crisis for Victoria in February 2000, as profiled by the IEA (2001: 123):

> The Victorian outages reflected a combination of unusual circumstances, including an industrial dispute, which had taken around 20 per cent of generating capacity off line, two unplanned generator outages, and an extremely high peak demand caused by a heat wave across southeastern Australia. The situation was exacerbated by Victorian government intervention to introduce a price cap and establish consumption restrictions, which prolonged the shortages and distorted market responses…The mandatory consumption restrictions introduced by the Victorian government over six days lowered demand in Victoria and had the perverse effect of electricity flowing from Victoria into New South Wales and South Australia while the restrictions were in place.

The illustration of NEMMCO's dispatch and spot pricing methodology highlights the inherent volatility of the spot price, which can lead to large variations in financial exposure. This is owing to the dependence of the pool process on both generator bidding strategies and the impact of the complex interaction of supply and demand factors on pricing. In a competitive electricity market, prices are inherently volatile as demand varies widely both within a day or week and across seasons within a year. Electricity consumption is difficult to predict and the lack of real-time pricing means demand is not very responsive to price changes. Further, the ability to quickly increase production beyond installed capacity is limited, and the high cost of idle capacity and the lack of economical storage, along with the fact that demand and supply must be continuously balanced to meet certain physical supply quality requirements (frequency, voltage and stability) together imply that prices reflect the underlying volatility in the cost of supplying electricity (ABARE 2002).

DATA AND SUMMARY STATISTICS

The data employed in the study are daily spot and futures prices for electricity in the New South Wales and Victoria regional markets and encompass the period 1 April 1999 to 31 December 2001. Spot price data is obtained from the National Electricity Market Company (NEMMCO, 2002) originally on a half-hourly basis representing 48 trading intervals in each

24-hour period. Following Lucia and Schwartz (2001) a series of daily arithmetic means is drawn from the trading interval data with prices calculated in Australian dollars per megawatt hours (Mwh). Although such treatment entails the loss of at least some 'news' impounded in the more frequent trading interval data, daily averages play an important role in electricity markets, particularly in the case of financial contracts. De Vany and Walls (1999a; 1999b) and Robinson (2000) all employ daily spot prices in their respective analyses of the western United States and United Kingdom spot electricity markets.

In order to highlight the different price formation processes in the peak and off-peak (base load) period electricity markets and to provide consistency with the futures price series, two separate daily average price series are constructed for each regional market. The peak period series is formed from the half-hourly trading intervals Monday to Friday from 7:00 to 21:00 hours. The off-peak period encompasses the remaining Monday to Friday half-hourly trading intervals. Categorisation of peak and off-peak (or base load) period prices in this manner is identical to that employed in the regional markets and as specified in the Sydney Futures Exchange futures contracts. Selected descriptive statistics for the electricity spot markets in New South Wales and Victoria are presented in Table 3.

<TABLE III HERE>

The futures data used in the study consists of daily closing prices for NSW and Victoria base load and peak period electricity contracts over the period 1 April 1999 to 31 December 2001. All information is obtained from the Sydney Futures Exchange (SFE, 2002). The contract unit in all instances is 500-megawatt hours (Mwh) of electrical energy and prices are quoted in Australian dollars per megawatt hour with a minimum price fluctuation of \$0.05 and a tick value of \$25.00 for up to thirteen months ahead. The daily futures closing prices are collected from each contract that is deliverable in one month (the most nearby contract month save the current contract month). On the first day of the next calendar month it is rolled over to the next contract that is deliverable in one month. For example, if the calendar-trading month is September, the daily closing prices are collected from the contract that is deliverable in October, and on the first day of October it is rolled over to the contract that is deliverable in November. While such a specification procedure ensures that the choice of contracts that are deliverable have a high degree of liquidity, it also implies that the maximum maturity length is two months and the minimum maturity length is one month. Nevertheless, Emery and Liu (2002) employ a comparable technique to provide a single time series of NYMEX electricity futures prices as does the study of NYMEX petroleum futures spreads by Girma and Mougoué (2002).

Table 3 presents the summary of descriptive statistics of the daily spot and futures prices for the two electricity markets. Samples means, medians, maximums, minimums, standard deviations, skewness, kurtosis, coefficient of variation and the Jacque-Bera statistic and *p*-value are reported. The highest spot prices are in the peak period for Victoria and in the off-peak period for NSW averaging \$43.69 and \$40.53 per megawatt-hour, respectively while the highest futures prices are in both the peak period contracts for both NSW and Victoria averaging \$37.91 and \$49.99 respectively The standard deviations for spot electricity range from \$44.25 (New South Wales in peak period) to \$179.45 (New South Wales in off-peak period) while the standard deviation for futures prices range between \$45.50 (Victoria off-peak period) to \$33.44 (Victoria peak period). For the eight electricity spot and futures markets, the value of the coefficient of variation (standard deviation divided by the mean price) measures the degree of variation in spot or futures price relative to the mean spot or futures price. Relative to the average spot or futures price, New South Wales (NSW) off-peak spot prices are the most variable while off-peak futures prices in New South Wales are the least variable.

The distributional properties of the spot price series generally appear non-normal. All of the electricity spot and futures markets are positively skewed and since the kurtosis, or degree of excess, in all of these electricity markets exceed three a leptokurtic distribution is also indicated. The calculated Jarque-Bera statistic and corresponding *p*-value in Table 3 is used to test the null hypotheses that the daily distribution of spot prices is normally distributed. All *p*-values are smaller than the .01 level of significance suggesting the null hypothesis is rejected. These daily spot and futures prices are then not well approximated by the normal distribution; such conditions normally meaning it is necessary to fit ARCH-type volatility models.

<TABLE IV HERE>

Lastly, each price series is tested for the presence of a unit root using the Augmented Dickey-Fuller (ADF) test. Table 4 presents the ADF unit root tests for the daily peak and off-peak spot and futures prices in the New South Wales and Victorian electricity markets. In all instances, the null hypothesis of nonstationarity is tested. Analysis of the price levels series indicates stationarity for all markets at the 0.05 level of significance or better with the exception of the Victorian futures market in the peak period. This series is stationary at the 0.10 level. The rejection of the unit root hypothesis implies that the series need not be differenced to achieve stationary which is a necessary condition required to avoid spurious results. The results lie contrary to previous empirical work by De Vany and Walls (1999a; 1999b) which found that US spot electricity prices contain a unit root and by Emery and Liu (2002) that NYMEX electricity futures are also non-stationary, though this study does concur with Lucia and Schwartz (2001) that electricity prices are stationary.

VOLATILITY MODELS

Since the data for the peak and off peak periods in both the New South Wales and Victorian spot and futures electricity markets exhibit heteroskedasticity, generalized autoregressive conditional heteroskedastistic (GARCH) models involving different lags can be appropriately employed to examine the relationship between these markets. Autoregressive conditional heteroscedasticity (ARCH) and generalised ARCH (GARCH) models that take into account the time-varying variances of univariate economic time series data have been widely employed. Suitable surveys of ARCH modeling in general and its widespread use in finance applications may be found in Bera and Higgins (1993) and Bollerslev et al. (1992) respectively. Pagan (1996) also contains discussion of developments in this expanding literature.

The following conditional equation accommodates the spot market's price and the price of the futures market maturing in two months time:

$$S_t = \alpha_1 + \alpha_2 F_{t+2} + \varepsilon_t \qquad (1)$$

where S_t is an $n \times 1$ vector of the natural logarithm of the daily spot prices at time t and F_{t+2} is an $n \times 1$ vector of the natural logarithm of the daily futures prices that matures in two months time, ε_t is the random error or innovation at time t, α_1 represent long-term drift coefficient and α_2 is the degree of mean spillover effect across markets, or put differently, whether the current price of the futures market can be used to predict the spot price (two months in advance). The conditional variance equation is denoted as:

$$\sigma_t^2 = \omega + \sum_{i=1}^{p} \beta_j \varepsilon_{t-j}^2 + \sum_{i=1}^{q} \gamma_j \sigma_{t-j}^2 \qquad (2)$$

where ω is the mean, the sum of the β_j*'s* is the news about the degree of innovation from the previous periods (ARCH terms), the sum of the $\gamma_{j's}$ is the previous period's forecast volatility spillover effects (GARCH terms) and the aggregation of β*'s* and γ*'s* coefficients measures the degree of persistence in volatility.

EMPIRICAL RESULTS

The estimated coefficients and standard errors for the New South Wales and Victorian peak period conditional mean price equations for electricity are presented in Table 5. Four different GARCH(p,q) models are estimated, ranging from a simple first-order GARCH term and a first-order ARCH term or GARCH(1,1) to a second-order GARCH term and a second-order ARCH term or GARCH(2,2). To select the most appropriate specification, *F*-statistics are first used to identify significant models, following which the Akaike information criterion (AIC) and Schwartz criterion (SC) select the most appropriate lag structure within these significant models by increasing the number of lags until the AIC and SC are minimised. For the NSW peak period market the AIC/SC criteria identifies a GARCH(1,2) model while the Victorian peak period market is best modelled with a GARCH(2,2) specification.

<TABLE V HERE>

For the two peak period electricity spot markets only NSW exhibits a significant mean spillover from the lagged futures price in the GARCH(1,2) model, while for the Victorian market while the GARCH(2,2) model is deemed the most appropriate the estimated mean spillover is insignificant. In the the case of NSW, the mean spillover is positive. For example, in NSW a $1.00 per megawatt-hour increase in its futures price will Granger cause an increase of $1.14 per megawatt-hour in its spot price over the two months. On the basis of these results we can conclude that there is a linear causality from futures prices to spot prices in the NSW electricity market. Such findings are consistent with the established notion that futures prices lead spot prices because the former react more quickly than the latter due to low transaction costs and ease of shorting. With a commodity such as electricity it is assured that the difficulty (read impossibility) in holding the physical commodity by speculators and the extreme storage constraints imposed upon hedgers implies that new information will be first reflected in the futures, rather than the spot markets.

The conditional variance equations incorporated in the paper's GARCH methodology effectively capture the information and volatility spillovers between the futures and spot electricity markets. Table 5 also presents the estimated coefficients for the variance covariance matrix of equations. These quantify the effects of the lagged cross innovations and lagged cross volatility persistence on the volatility of the spot markets. The coefficients of the variance covariance equations are overwhelmingly significant for innovations and volatility spillovers to the spot prices for both electricity markets, indicating the presence of strong

ARCH and GARCH effects. In evidence, 100 percent (twelve out of twelve) of the estimated ARCH coefficients and 100 percent (twelve out of twelve) of the estimated GARCH coefficients in the four estimated models for NSW and Victoria are significant at the .01 level or lower. The sum of the ARCH and GARCH coefficients measures the overall persistence in the markets. Both electricity markets exhibit strong persistence volatility ranging from 0.8967 for Victoria to 0.9861 for NSW. Measures of persistence close to one are indicative of market inefficiency in the transfer of information between futures and spot markets with the suggestion that the Victorian futures and spot market are relatively less efficient than the NSW market in this respect.

The estimated coefficients and standard errors for the New South Wales and Victorian off-peak period conditional mean and variance price equations for spot electricity are presented in Table 6. Once again, the Akaike and Schwartz criteria are employed to select between the four different GARCH(p,q) models estimated, of which a GARCH(1,2) and a GARCH(1,1) are found to be most appropriate for the NSW and Victorian markets respectively. Both NSW and Victoria exhibit a significant and positive mean spillover from the lagged futures price to the spot price. For example, a $1.00 increase in the NSW lagged futures price is associated with a $0.77 increase in the spot price over the next two months, while a $1.00 increase in the Victorian lagged futures price is associated with a $0.40 increase in the spot price.

<TABLE VI HERE>

The coefficients of the variance equations are overwhelmingly significant for innovations and volatility spillovers to the spot prices for the off-peak period electricity markets, indicating the presence of strong ARCH and GARCH effects. The measures of persistence, or the inefficiency regarding information transfer from the futures to the spot market range are 0.6598 for the NSW market and 0.1646 for the Victorian market. As compared to the peak period spot and futures markets, persistence is generally lower, suggesting a greater degree of efficiency in the off-peak markets concerning the transfer of information from futures to spot prices.

Table 7 presents the results of a simulation analysis of the forecasting ability of the four spot/futures models selected through the AIC and SC criteria; namely a GARCH(1,2) for NSW peak and off-peak period price equations and a GARCH (2,2) and GARCH(1,1) for the Victorian peak and off-peak period price equations, respectively. The mean absolute and mean absolute percentage errors avoid the problem of positive and negative errors canceling each other out. The mean absolute percentage error indicates that futures prices are a generally better predictor of spot prices in either NSW market than in the Victorian market, while predictions are more accurate in either market for off-peak and than peak period spot prices. These results flow from the greater degree of inefficiency in the transfer of information from futures to spot markets in general, and the greater degree of information transfer for the NSW market specifically.

<TABLE VII HERE>

Thiel's inequality coefficient is also presented in Table 7 for the four GARCH models. Bounded by 0 and 1, when Thiel's coefficient is equal to 1, simulated values are always 0 when actual values are nonzero, or nonzero predictions are obtained when actual values are zero. The bias, variance and covariance proportions break down the simulation error into its components. The bias proportion is an indication of systematic error since it measures the extent to which the average values of the simulated and actual series deviate from each other. With biases relatively close to zero, the indication is that the models employed do not require significant revision.

In a similar manner, the covariance proportion indicates unsystematic errors however since it is unreasonable to expect that predictions be perfectly correlated with actual values, larger values of this measure are of less concern. Nonetheless, the indication is that relatively larger components of forecast error are associated with unsystematic errors in the NSW market than in the Victorian market, though the off-peak market in NSW has more unsystematic error than the peak, while in Victoria the situation is reversed. Unfortunately, the variance proportion of the decomposition indicates the ability of the models selected to replicate the degree of variability in the variable of interest; namely, the spot price. The large values here indicate that the actual series has fluctuated considerably while the simulated series shows little fluctuation. This infers that the futures models for Victoria have considerably underestimated the variability in the spot price of electricity, and the models for NSW futures to a lesser extent.

CONCLUSION

This paper highlights the transmission of prices and price volatility between Australian electricity spot and futures markets in NSW and Victoria during the period 1999 to 2001. All of these spot markets are member jurisdictions of the recently established National Electricity Market (NEM). At the outset, unit root tests confirm that Australian electricity spot prices are stationary. A generalised autoregressive conditional heteroskedasticity (GARCH) model is used to identify the source and magnitude of spillovers. The estimated coefficients from the conditional mean price equations indicate that the mean spillovers are positive. This would suggest, for the most part, that spot electricity prices could be usefully forecasted using lagged price information from the futures market. However, innovation and volatility spillovers are also significant for nearly all markets, indicating the presence of strong ARCH and GARCH effects. Combined together, persistence in the transfer of information from futures to spot markets is high, such inefficiency suggesting that volatility shocks tend to persist and affect future spot prices for a long period of time.

This analysis could be extended in a number of ways. One approach would be to estimate a system of non-symmetrical conditional variance equations for an identical set of data. This would allow the analysis of volatility innovations and persistence to vary according to the direction of the information flow. Unfortunately, strict computing requirements did not permit the application of this model with the electricity markets specified in the analysis. Another useful extension would be to examine each of the electricity markets individually and in more detail. For example, while the sample for this study is determined by the period of tenure of the National Electricity Market (NEM) wholesale electricity spot markets in the separate states pre-date this by several years. An examination of the interconnection between the long-standing electricity spot markets in NSW and VIC would be particularly useful and examination of spot and futures markets in different regions using, say, multivariate GARCH techniques would throw further light on the relationships between electricity futures and spot prices.

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TABLE I

Generator Offer Prices and Total Electricity Demand per Half-hour

Generator	Generator Offer Prices (half-hour)	Time	Total Demand (MW)
6	$40/MWh	12:05pm	290
5	$38/MWh	12:10pm	330
4	$37/MWh	12:15pm	360
3	$35/MWh	12:20pm	410
2	$33/MWh	12:25pm	440
1	$32/MWh	12:30pm	390

TABLE II

Dispatch of Generation and Spot Price Calculation

Graph point price	Dispatch $/MWh	Time demand	Total (MW)	Scenario
Point A	35	12:05pm	290	Generators 1 & 2 are fully utilised. Generator 3 is partially utilised.
Point B	37	12:10pm	330	Generators 1,2 & 3 are fully utilised. Generator 4 is partially utilised.
Point C	37	12:15pm	360	Generators 1,2 & 3 are fully utilised. Generator 4 is partially utilised.
Point D	38	12:20pm	410	Generators 1,2, 3 & 4 are fully utilised. Generator 5 is partially utilised.
Point E	38	12:25pm	440	Generators 1,2, 3 & 4 are fully utilised. Generator 5 is partially utilised.
Point F	37	12:30pm	390	Generators 1,2 & 3 are fully utilised. Generator 4 is partially utilised.

The spot price is calculated as: ($35/MWh + $37/MWh + $37/MWh + $38/MWh + $38/MWh + $37/MWh) / 6 = $37/MWh

TABLE VII

Forecast accuracy for peak and off-peak (base load) period spot prices using futures prices

Region	NSW	NSW	VIC	VIC
Market	Peak	Off-peak	Peak	Off-peak
Model	GARCH(1,2)	GARCH(1,2)	GARCH(2,2)	GARCH(1,1)
Root mean squared error	0.5004	0.5100	0.5857	0.6124
Mean absolute error	0.3423	0.2884	0.4089	0.3468
Mean absolute percentage error	9.3511	8.5221	11.4772	10.3144
Theil inequality coefficient	0.0728	0.0793	0.0838	0.0960
Bias proportion	0.0542	0.0002	0.0071	0.0001
Variance proportion	0.4232	0.6328	0.9408	0.8004
Covariance proportion	0.5226	0.3671	0.0521	0.1995

FIGURE I

Least Cost Dispatch and Generator Utilisation

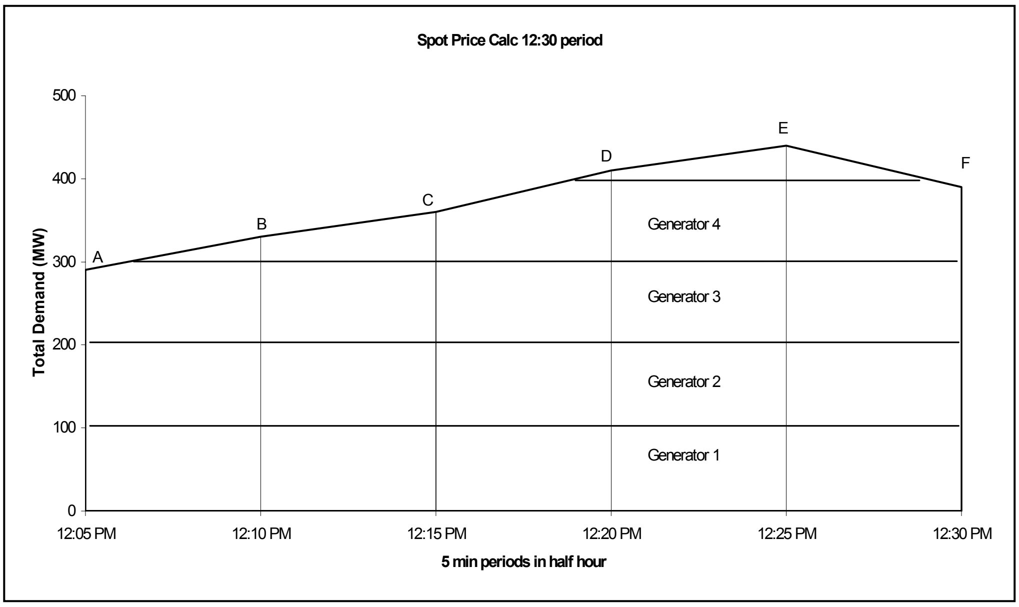

TABLE III

Summary Statistics of Daily Spot and Futures Prices for Australian Electricity Markets, 1999-2001

	Peak period prices				Off-peak (base load) period prices			
	NSW		VIC		NSW		VIC	
	Spot	Futures	Spot	Futures	Spot	Futures	Spot	Futures
Mean	38.9561	37.9142	43.6980	49.9970	40.5343	30.2290	41.8710	30.9687
Median	30.1512	38.0000	30.0981	37.1250	22.7271	30.0000	21.3263	30.5000
Maximum	585.3686	80.5000	1658.6050	167.4500	2368.4990	48.0000	1497.3710	45.5000
Minimum	13.3610	25.0000	4.2003	22.2500	9.6137	22.0000	6.1663	21.5000
Std. Dev.	44.2514	6.6049	81.7951	33.4473	179.4757	4.8580	150.3377	5.6233
Skewness	7.9404	1.6627	13.2834	2.0621	11.7769	1.0241	8.6195	1.3399
Kurtosis	81.4487	10.0602	230.3570	6.7646	140.9607	4.1059	77.0923	4.5694
CV	1.1359	0.1742	1.8718	0.6690	4.4277	0.1607	3.5905	0.1816
Jarque-Bera	1.9E+05	1.8E+03	1.5E+06	9.3E+02	5.8E+05	1.6E+02	1.7E+05	2.8E+02
JB *p*-value	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000

Notes: NSW – New South Wales, VIC – Victoria; CV – coefficient of variation; JB – Jarque-Bera.

TABLE IV

Augmented Dickey-Fuller Unit Root Tests

Peak market level series		Off-peak (base load) level series	
NSW Spot	-5.5978^{***}	NSW Spot	-6.5996^{***}
NSW Futures	-3.9088^{***}	NSW Futures	-3.0820^{**}
VIC Spot	-8.0812^{***}	VIC Spot	-7.0738^{***}
VIC Futures	-2.5527^{***}	VIC Futures	-3.0073^{**}

Notes: Hypotheses H_0: unit root, H_1: no unit root (stationary). The lag orders in the ADF equations are determined by the significance of the coefficient for the lagged terms. Only the intercepts are included in the levels series. Asterisks denote significance at: *** – .01 level, ** – .05 level and * – .10 level. Critical values are -3.4393 – .01 level, -2.8654 – .05 level, and -2.5689 – .10 level.

TABLE V

Estimated mean and variance equations for peak period electricity markets

		GARCH(1,1)			GARCH(1,2)			GARCH(2,1)			GARCH(2,2)		
		Coefficient	Std. error	p-value	Coefficient	Std. error	p-value	Coefficient	Std. error	p-value	Coefficient	Std. error	p-value
New South Wales	α_1	-0.9043	0.2730	0.0009	-0.7998	0.2654	0.0026	-1.2869	0.3319	0.0001	-0.9788	0.3564	0.0060
	α_2	1.1637	0.0753	0.0000	1.1474	0.0726	0.0000	1.2891	0.0921	0.0000	1.2074	0.0987	0.0000
	ω	0.0161	0.0019	0.0000	0.0352	0.0026	0.0000	0.0101	0.0029	0.0006	0.0141	0.0024	0.0000
	β_1	0.5067	0.0372	0.0000	0.6215	0.0449	0.0000	0.6354	0.0554	0.0000	0.5824	0.0534	0.0000
	β_2	–	–	–	–	–	–	-0.5059	0.0540	0.0000	-0.4330	0.0269	0.0000
	γ_1	0.5644	0.0207	0.0000	-0.0210	0.0073	0.0039	0.8474	0.0452	0.0000	0.7156	0.0377	0.0000
	γ_2	–	–	–	0.3856	0.0283	0.0000	–	–	–	0.0901	0.0252	0.0004
	$\beta+\gamma$	1.0711	–	–	0.9861	–	–	0.9768	–	–	0.9552	–	–
	R_2	-0.0007	–	–	0.0477	–	–	0.0622	–	–	0.0740	–	–
	Adj.R^2	-0.0064	–	–	0.0410	–	–	0.0556	–	–	0.0662	–	–
	ln$L$	-401.8215	–	–	-389.0238	–	–	-392.9983	–	–	-391.0597	–	–
	AIC	1.1332	–	–	1.1003	–	–	1.1114	–	–	1.1088	–	–
	SC	1.1651	–	–	1.1386	–	–	1.1497	–	–	1.1534	–	–
Victoria	α_1	3.3581	0.1093	0.0000	3.3008	0.1226	0.0000	3.3715	0.1205	0.0000	3.5528	0.1212	0.0000
	α_2	0.0112	0.0288	0.6980	0.0327	0.0318	0.3036	0.0065	0.0328	0.8426	-0.0283	0.0317	0.3715
	ω	0.0436	0.0040	0.0000	0.0534	0.0035	0.0000	0.0671	0.0050	0.0000	0.0646	0.0059	0.0000
	β_1	0.3971	0.0386	0.0000	0.2595	0.0261	0.0000	0.1636	0.0447	0.0003	0.0904	0.0297	0.0023
	β_2	–	–	–	–	–	–	0.4020	0.0591	0.0000	0.4251	0.0025	0.0000
	γ_1	0.5630	0.0271	0.0000	0.9639	0.0309	0.0000	0.3651	0.0298	0.0000	-0.0677	0.0130	0.0000
	γ_2	–	–	–	-0.3342	0.0156	0.0000	–	–	–	0.4489	0.0270	0.0000
	$\beta+\gamma$	0.9601	–	–	0.8892	–	–	0.9307	–	–	0.8967	–	–
	R_2	-0.0258	–	–	-0.0125	–	–	-0.0286	–	–	-0.0109	–	–
	Adj. R^2	-0.0316	–	–	-0.0196	–	–	-0.0359	–	–	-0.0194	–	–
	ln$L$	-572.6627	–	–	-563.7663	–	–	-566.2573	–	–	-545.1959	–	–
	AIC	1.6091	–	–	1.5871	–	–	1.5940	–	–	1.5382	–	–
	SC	1.6410	–	–	1.6253	–	–	1.6323	–	–	1.5828	–	–

Notes: Mean equation coefficients are denoted α_1 and α_1; variance equation ARCH terms are denoted β_1 and β_2; ω is the variance equation constant; variance equation GARCH terms are denoted γ_1 and γ_2; $\beta+\gamma$ is a measure of persistence; Adj. R^2 is the adjusted R^2; ln$L$ is the log-likelihood, AIC – Akaike Information Criterion; SC – Schwartz Criterion.

TABLE VI

Estimated mean and variance equations for off-peak (base load) period electricity markets

		GARCH(1,1)			GARCH(1,2)			GARCH(2,1)			GARCH(2,2)		
		Coefficient	Std. error	p-value	Coefficient	Std. error	p-value	Coefficient	Std. error	p-value	Coefficient	Std. error	p-value
New South Wales	α_1	0.6022	0.6673	0.3668	0.5633	0.6307	0.3718	0.4986	0.7121	0.4838	0.5000	0.7234	0.4894
	α_2	0.7711	0.1930	0.0001	0.7754	0.1820	0.0000	0.7951	0.2059	0.0001	0.7966	0.2088	0.0001
	ω	0.0910	0.0120	0.0000	0.0972	0.0105	0.0000	0.1693	0.0779	0.0298	0.1751	0.0096	0.0000
	β_1	-0.0168	0.0005	0.0000	-0.0156	0.0007	0.0000	0.0121	0.0244	0.6190	0.0046	0.0192	0.8122
	β_2	–	–	–	–	–	–	-0.0233	0.0131	0.0752	-0.0196	0.0096	0.0403
	γ_1	0.7458	0.0350	0.0000	0.6754	0.2397	0.0048	0.5228	0.2229	0.0190	0.4776	0.3206	0.1362
	γ_2	–	–	–	0.0280	0.2216	0.8994	–	–	–	0.0393	0.3181	0.9016
	$\beta+\gamma$	0.7290	–	–	0.6598	–	–	0.5117	–	–	0.5019	–	–
	R_2	0.0501	–	–	0.0535	–	–	0.0601	–	–	0.0528	–	–
	Adj.R^2	0.0448	–	–	0.0468	–	–	0.0317	–	–	0.0448	–	–
	ln$L$	-539.9128	–	–	-532.4653	–	–	-542.4088	–	–	-544.4601	–	–
	AIC	1.5179	–	–	1.4999	–	–	1.5276	–	–	1.5361	–	–
	SC	1.5497	–	–	1.5381	–	–	1.5658	–	–	1.5807	–	–
Victoria	α_1	1.7666	0.4966	0.0004	1.6672	0.5107	0.0011	1.7368	0.5381	0.0012	1.8055	0.5590	0.0012
	α_2	0.4065	0.1435	0.0046	0.4301	0.1481	0.0037	0.4155	0.1557	0.0076	0.3946	0.1615	0.0145
	ω	0.3496	0.0131	0.0000	0.2669	0.0328	0.0000	0.0375	0.0040	0.0000	0.0443	0.0056	0.0000
	β_1	0.2390	0.0832	0.0041	0.0771	0.0183	0.0000	0.2944	0.0207	0.0000	0.2642	0.0120	0.0000
	β_2	–	–	–	–	–	–	-0.2793	0.0161	0.0000	-0.2481	0.0124	0.0000
	γ_1	-0.0744	0.0261	0.0043	-0.2441	0.0601	0.0000	0.8925	0.0139	0.0000	0.8963	0.0215	0.0000
	γ_2	–	–	–	0.4779	0.0317	0.0000	–	–	–	-0.0226	0.0152	0.1376
	$\beta+\gamma$	0.1646	–	–	0.3108	–	–	0.9076	–	–	0.8898	–	–
	R_2	0.0118	–	–	0.0102	–	–	0.0118	–	–	0.0117	–	–
	Adj. R^2	0.0062	–	–	0.0032	–	–	0.0049	–	–	0.0034	–	–
	ln$L$	-651.0194	–	–	-647.1888	–	–	-629.8775	–	–	-629.5492	–	–
	AIC	1.8274	–	–	1.8195	–	–	1.7712	–	–	1.7731	–	–
	SC	1.8592	–	–	1.8577	–	–	1.8095	–	–	1.8177	–	–

Notes: Mean equation coefficients are denoted α_1 and α_1; variance equation ARCH terms are denoted β_1 and β_2; ω is the variance equation constant; variance equation GARCH terms are denoted γ_1 and γ_2; $\beta+\gamma$ is a measure of persistence; Adj. R^2 is the adjusted R^2; ln$L$ is the log-likelihood, AIC – Akaike Information Criterion; SC – Schwartz Criterion.