ARTICLE IN PRESS

ELSEVIER

Energy Policy ▮ (▮▮▮▮) ▮▮▮–▮▮▮

ENERGY POLICY

www.elsevier.com/locate/enpol

Empirical observations of bidding patterns in Australia's National Electricity Market

Xinmin Hu*, George Grozev, David Batten

CSIRO Manufacturing and Infrastructure Technology, P.O. Box 56, Highett, Victoria 3190, Australia

Abstract

For more than a decade, electricity industries have been undergoing reform worldwide. However, there are various, sometimes contradictory, conclusions about the performance of these restructured electricity markets. Market performance depends largely on how each market participant responds to the market design — including market rules, market operational procedures, and information revelation. In this paper, we identify and examine the strategies adopted by generators in Australia's National Electricity Market, based on publicly available data for the period from May 1, 2002 to May 31, 2003. We try to understand and answer some basic questions like how generators respond collectively or individually to changes in market conditions (e.g. load changes) and why they behave in this way. The statistics calculated from the data show that wide variations in the frequency of strategic bidding and rebidding exist; that generators more frequently use capacity offers as a strategic tool than price offers; that large generating units are more likely to use capacity strategies to control market prices; and that generators are capable of responding to changes in market conditions.

Keywords: Electricity markets; Market power; Bidding strategies

1. A brief introduction to the National Electricity Market

The Australian National Electricity Market (NEM) is a gross pool-type market comprising four states: Queensland (QLD), New South Wales (NSW), Victoria (VIC), South Australia (SA) and the Australian Capital Territory (ACT). It commenced operations on December 13, 1998, having emerged from the former pool markets in NSW and VIC. Currently, it is divided into five regions: QLD, NSW, VIC, SA and Snowy. Tasmania is expected to join the NEM in 2005/2006 when the undersea Basslink is completed. At the moment, Western Australia and the Northern Territory are not physically connected to the eastern electricity network.

The National Electricity Market Management Company (NEMMCO) is the market operator (ISO—independent system operator) and there are about 160 market-scheduled generating units out of a total of 192 generating units. The total registered capacity was around 38 000 MW in 2002/2003. There are two unregulated, interregional transmission links (a third is under construction) whose revenue depends fully on the regional market prices. The other four (groups of) interregional links are regulated. Each state has its own distribution network operators. These regional network operators plan the network links and develop constraint equations for network flows and network service tariffs. The National Electricity Code—with objectives and market rules managed by the National Electricity Code Administrator (NECA)—guides the operation and further reform of the NEM.

In the NEM, a settlement day starts at 04:00 and ends at 04:00 the next day. Each settlement interval is a half-hour period starting on the hour or half-hour. For example, settlement interval 6 denotes the period from 06:30 to 07:00. Each dispatch interval is a 5-min interval.

The NEM is operated as follows:

(1) Scheduled generators submit offers in 10 price bands, stacked in an increasing order over a settlement day and in 10 incremental quantity

*Corresponding author. Tel.: +61-3-9252-6109; fax: +61-3-92526249.

E-mail address: Xinmin.Hu@csiro.au (X. Hu).

0301-4215/$ - see front matter © 2004 Elsevier Ltd. All rights reserved.
doi:10.1016/j.enpol.2004.04.003

bands. These quantity offers correspond to the 10 price bands for each of the 48 settlement intervals, and must be received by NEMMCO before noon of the previous day (i.e. a day before the real dispatch).[1]

(2) Demand forecasts are made to NEMMCO by regional network operators for each region. NEMMCO runs a linear program to dispatch generation and meet demand every 5 min. This program aims to maximize the value of trade based on dispatch bids or offers from market participants along with other ancillary services, subject to constraints on the physical network and the generating units. This means the less-expensive generating units are dispatched first, but the price offered by the most expensive generating unit dispatched determines the price for that dispatch interval.

(3) The settlement price for each settlement interval is the average of all prices over the six dispatch intervals in the settlement interval.

The price cap (or VOLL—value of the lost load) in the NEM is currently \$10 000/MWh, an increase from \$5000/MWh from April 2002 onward.[2] In practical terms, generators can bid their price bands up to this figure, knowing that the market price is capped by this limit.

1.1. Available information

Market information plays an important role in ensuring the reliable operation of the NEM and in the decision making of participants. NEMMCO provides market participants with information such as load forecasts, pre-dispatch (and price sensitivity analysis) data, dispatch data, as well as medium- (7 days) and long-term (2 years) forecasting of supply scenarios or system adequacy. Market participants are permitted to adjust their bids in response to the latest information. For example, they can rebid the quantity for a previously bid settlement interval up to 5 min before dispatch, although the price bands are fixed for the entire settlement day.

We used NEMMCO's publicly available registration files to identify market-scheduled generating units and transmission service providers, regions and owners of a generating unit or a transmission line, generating technologies and the nominal capacities of the generating units.

On its website,[3] NEMMCO publishes the bids from market participants and the dispatch data for all scheduled generating units shortly after the end of a settlement day. These 'yesterday bid' files contain offers/bids and rebids made by generating units and dispatchable loads for each day's settlement intervals. They have also recorded the rebid explanations since early 2002. The daily dispatch files include regional information such as regional reference prices, total demand and dispatchable generation/load. The yesterday bid and daily dispatch files from May 1, 2002 to May 31, 2003 are used in this paper. Barmack (2003) raises some concerns about the revelation of bidding data to the public. However, we shall demonstrate the positive sides of the data revelation in this paper.

1.2. Purposes and goals of the paper

Electricity industries worldwide have been restructuring for more than a decade and there are various, sometimes contradictory, conclusions about their performance. Of particular interest is the strategic behaviour of market participants. Such behaviour has been studied and debated by a broad spectrum of people—including academics, industrial practitioners, politicians and regulators.

Australia is one of many countries restructuring their electricity industries. Several researchers have studied the market's performance during this period of restructuring. Wolak (1999) examined the first three months of the NEM's operation and observed that wholesale prices in VIC and NSW dropped initially compared with those prevailing prior to the introduction of the NEM. Outhred (2000) concluded that the extent of competition in the NEM is high and that the market performs well. By way of contrast, Short and Swan (2002) reported a mixed performance based upon their calculation of Lerner indices, which are defined as the ratios of the difference of bid price and marginal price to the bid price (see e.g. California ISO, 1999), for the regions in the NEM.

Methods such as game theory, behavioural science and agent-based computational economics have been employed to model participants' decision processes in these restructured electricity markets. Various assumptions are often made on the objectives, strategies, beliefs and capabilities of participants. In game theory models, for example, participants are assumed to be rational in the sense that they are capable of obtaining and exploring all the relevant information in order to deduce the outcome. Some of these rigid assumptions can be relaxed with the help of agent-based simulation, since participants are allowed to have various objectives and be subject to different sets of rules to guide their

[1] If the market price (in the 5-min dispatch interval of the settlement interval in question) is greater than or equal to a price band in the bid, then the generator has signalled his willingness to sell the aggregated quantity up to this price band.

[2] Prices are in Australian dollars.

[3] www.nemmco.com.au.

behaviour. They may have access to different information and possess different computational capabilities. The challenge in this case is how to assign a particular agent the appropriate set of behavioural rules and computational capabilities.

The electricity market is a complex evolving system of complicated interactions between nature, physical structures, market rules and participants. Each participating agent faces *risk* and *volatility* as they pursue their *goals*, and make decisions based on limited information and their *mental models* of how they believe the system operates. There are wide diversities of agents; they may have very different power capacities; they use different generation technologies; some only provide market services; they are located in different jurisdictional areas; they have different ownership; they are physically located at different nodes on the grid, and they face different grid constraints. Moreover, the objectives, beliefs and decision processes of these participants vary from one to another. Of interest is whether these wide diversities lead to diversities of market behaviours.

We hope to achieve two rather ambitious goals in this paper. The first is to identify various strategies used by generators in the marketplace, to help in designing suitable agent architectures in agent-based simulation models (see e.g. Bunn and Oliveira, 2001; North et al., 2002). The second is to identify and understand market power issues in the NEM (see e.g. Short and Swan, 2002; Wolak, 1999). The market power issues, which are relevant to the bidding strategies used by generators, concern market designers, regulators and consumers etc., because abuse of market power leads to market inefficiencies and further reforms of the market itself.

2. Empirical observations on bidding strategies in the NEM

To understand the bidding strategies available to generators, one needs to be familiar with the decision-making environment that generators face. These follow from the unique characteristics of supply and demand in the case of electricity. There are physical limits on a generating unit. It cannot be switched on and off frequently within a short time period as it has a minimum on/off time for efficient and safe operation. The start-up cost is also significant for nuclear or coal generating units. Limits on ramp rates prevent a generating unit from increasing or decreasing to a specific generation level instantaneously.

There are also economic factors associated with the operation of a generating unit. The operating cost of a unit depends on its generation level. For most generating units, an efficient level is achieved near its nominal capacity (see e.g. Brennan, 2003). Earned revenue needs to recover not only the incremental cost —which is the sum of fuel cost and variable operating and maintenance (O&M) costs—but also the fixed cost of building the generating unit. Each generator is expected to earn a reasonable rate of return. In order to survive and earn a reasonable profit, each generator must set prices above the marginal cost level.

Demand plays a vital role in all the aforementioned factors. Although it follows daily, weekly and seasonal usage patterns, demand displays additional volatility. Real-time balancing of supply and demand, together with the marginal pricing mechanism based on the merit order of bids, produces this extra volatility. This further complicates an already uncertain stream of likely revenues. Thus, a generator has to be adaptive, responding in a flexible way to changes in demand in order to maximize economic returns. In the following section, we illustrate the dynamics of prices and demands in four regions since the inception of the NEM.

2.1. Load and price dynamics in the NEM

The observed volatility and periodicity of demand affect many other market phenomena—such as prices and bidding behaviour. Deeper insights into these characteristics can help us understand the bidding behaviours of generators. Figs. 1 and 2 display the load and price dynamics from December 7, 1998 to May 31, 2003 for the NSW and QLD regions, respectively. The

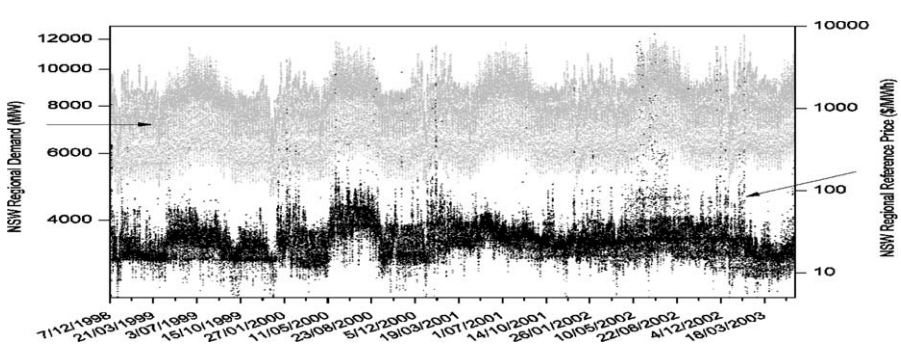

Fig. 1. Demand and price dynamics in the NSW region.

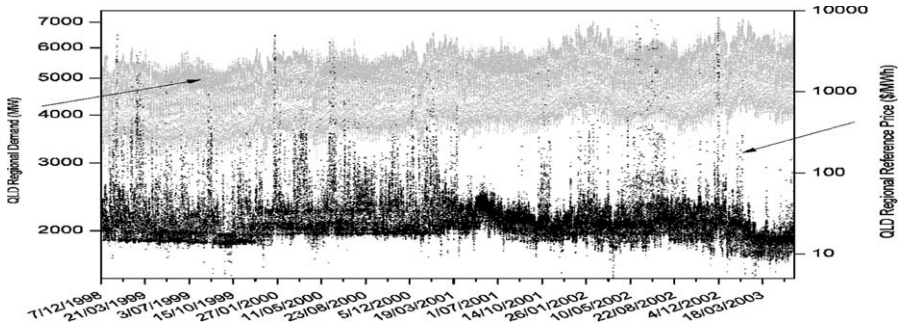

Fig. 2. Demand and price dynamics in the QLD region.

left vertical axes are for regional demands and right ones are the regional price in the logarithmic scale. Each dot in the graphs stands for the demand/price data point in each 30 min trading interval.

These graphs show the growth of peak demand and the steady baseline load growth in both regions, which is particularly significant in QLD. There are price spikes during high demand periods in both regions. However, these price spikes occurs more frequently in QLD than in NSW due to limited transmission and generation capacities in QLD.

The figures also show that demand for electricity is price-inelastic. This lack of price responsiveness is due to the fact that the prices paid by most consumers are regulated by State Governments and are set by retailers. Therefore, they are not players in the market game and are insulated from the volatility in real-time prices in the market. Thus consumers are not a focus in this paper. Nevertheless, more active and direct participation on the demand side is a necessary condition for a more effective and equitable market in the future.

Timing is also an important factor when a generator develops a bidding strategy, since the demand side displays some recognizable patterns. These cyclical patterns play an important part in determining intra-daily price levels. This variation is reflected in Fig. 3, which shows the price distribution in NSW for the early morning (04:05) and the evening peak (17:40) dispatch intervals based on data from May 2002 to May 2003. Prices in the 17:40 dispatch interval are spread over a much wider range than those in the 04:05 interval. There are two possible explanations for this phenomenon. One is that the supply curve becomes progressively and fundamentally steeper as the demand increases; therefore prices become more sensitive to variations of demand comparing with lower demand levels. The other is that generators tune their decisions more carefully in this peak interval than at other times. Such a finer decision can help to cope with price volatility and load variation. Ironically, it may create a more volatile price pattern as well.

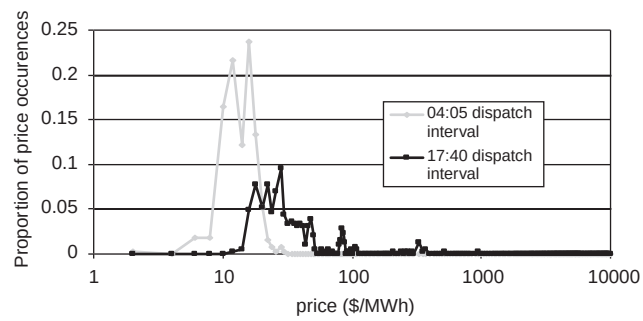

Fig. 3. Price distribution for the 04:05 and 17:40 dispatch intervals in NSW.

2.2. Diversity of bidding strategies among market participants

We call the vector of (10) price bands in any bid a *price vector* and the (10) quantity bands corresponding to these price bands (for each of the 48 settlement intervals) a *quantity vector*. We believe that the number of different price vectors and quantity vectors used by a generator provide a measure of the frequency of changes in a participant's bidding strategy. If the number of different price vectors and quantity vectors employed during a peak demand period (18:00) are both less than 20 (390 days are covered due to missing data for several days in the study period), then the unit is said to be *inactive*; if the sum of the numbers of price and quantity vectors is between 40 and 80, then the unit is said to be *moderately active*; all units with the sum of the numbers of price and quantity vectors greater than 80 are said to be *active*.

The data shows that many participants rarely change their offers/bids, while a minority do actively respond to changes in market conditions. There are 104 units classified as inactive, 28 as moderately active and 30 as active (see Fig. 4). The capacity shares of active and inactive units are 40% of the total market capacity and the rest is composed of the moderately active units. However, most of the active generators are base-load units that tend to dominate the supply side. In fact, the

30 active generating units are the 'giants' in their regions (two hydro generators each with capacity 1500 MW, 12 coal units of 660 MW each, 3 coal units of around 420 MW each, 10 units of 200–400 MW each and three small hydro generating units). Their greater size gives these generators more opportunities to try different combinations of capacity offers in different price bands. Moreover, size renders the generators a more secure and confident position: they can afford to try different strategic bids since part of the bulk of their capacity can be committed to very low price bands, safe in the knowledge that it is virtually certain of being dispatched. This 'frees up' the rest of their capacity for experimental bidding in 'strategic' price bands. Later we will see that they are also among those generating units that have the capability to influence regional prices, which to some extent, explains why these generating units are engaged in active strategic bidding.

2.2.1. Price strategy versus capacity strategy

The price and quantity bands are the key strategic variables that a generator can use to control its revenue from the NEM. A question then arises: do generators make use of price bands as a strategic variable more often than they use quantity bands (capacity commitment) as a strategic variable?

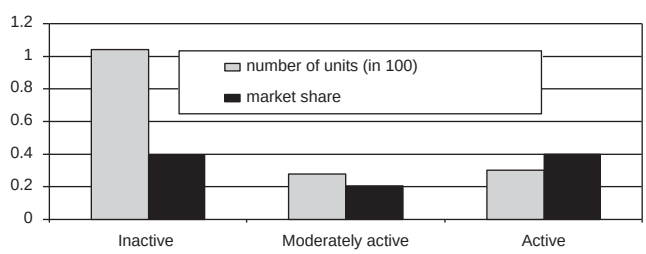

Fig. 4. Distribution of active, moderately active and inactive generating units.

Fig. 5 shows how many different price and quantity vectors (at 04:30 and 18:30) have been used by the active generators during our study period. The owners of these generating units may have several similar generating units at the same location, and similar patterns are observed for these units (only one shown in Fig. 5).

The full range of quantity vectors actually used by generators is much bigger than that shown here. Generators may change their quantity offers many times by rebidding for any settlement interval. Only the default or daily bids are used to define their *activeness* without taking account of rebids.

Fig. 5 shows that generators are more likely to use quantity offers rather than price offers in order to improve their market positions. This is especially the case in peak demand periods. Several reasons may contribute to this phenomenon:

(1) The load curve/shape is a reliable and visible factor in their decision-making processes, and thus quantity becomes the most important decision variable.
(2) Generators can shift quantity commitments up or down between different price bands, thereby achieving a similar effect to changing prices directly.
(3) Price offers are supposed to more or less reflect generators' marginal costs (fuel, O&M, capital costs etc.) plus their expected profit, a measure that most generators would not be keen to divulge.

There are implications of these observations to researchers who model generators' decision-making. To reflect reality, models should take account of generators' asset profiles, generation technologies, types of services and risk attitudes. The capability and willingness of generators to radically change existing strategies play important roles in their decision making.

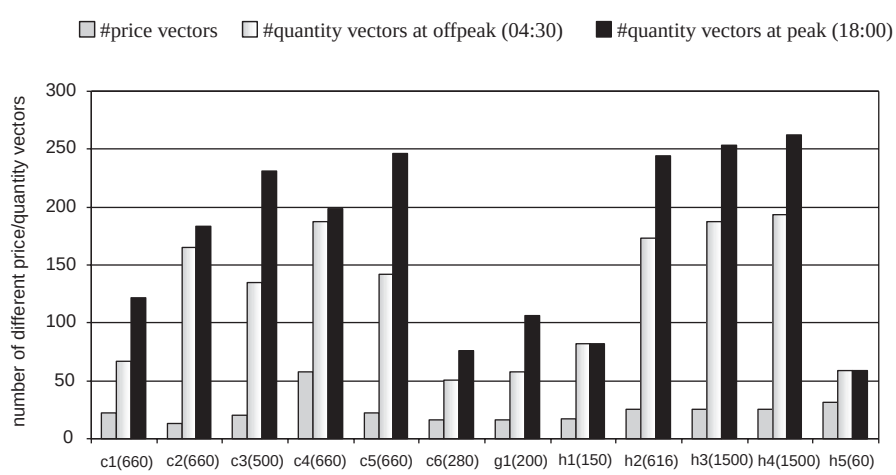

Fig. 5. Numbers of price/quantity vectors used by active generating units. (Coal generating units are labelled as c1, c2,…, gas units as g1, g2,…, hydro units as h1, h2,…, and the numbers in brackets are their capacities (MW).)

More interestingly, our observations suggest that generators behave more like Cournot players (i.e. using quantity as a strategic variable) in traditional game theory models.

2.3. Capacity strategies and market power

Whether intentional or otherwise, the strategy of capacity withholding by generators has the effect of raising prices. Such outcomes have been observed in several deregulated electricity markets, such as in California (see e.g. Borenstein et al., 2002), Britain (see e.g. Wolfram, 1999) and Australia (see e.g. Short and Swan, 2002). Capacity withholding can be accomplished in two ways. One is to offer capacity only in very high price bands. The other is to reduce the availability of one or more generating units. The important question is whether generators use these strategies regularly or just occasionally. Fig. 6 shows that a few generators do withhold their capacities quite often. In fact, the strategy of withholding capacity is used by the larger generators who own the larger generating units. However, the capacity withholding more often happens during peak periods, which can be identified by comparing the capacity commitment in offpeak, shoulder and peak periods (see also Fig. 7).

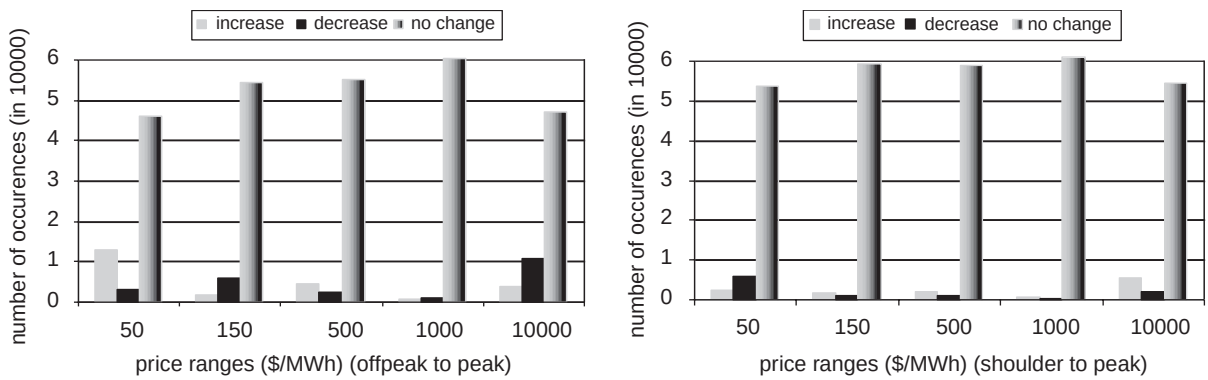

Fig. 6. Changes of capacity offers from offpeak and shoulder periods to peak periods.

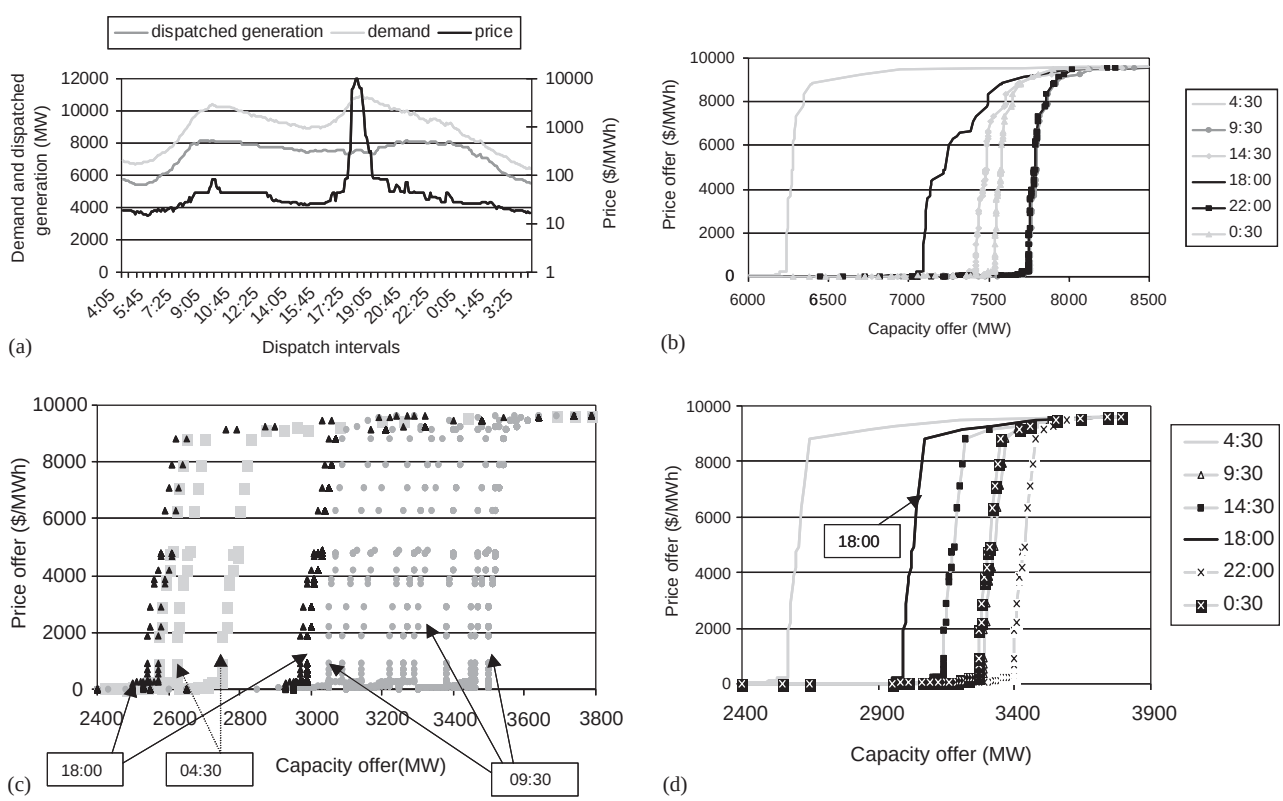

Fig. 7. (a) NSW regional demand, dispatched generation and regional prices. (b) Regional supply stacks on June 29, 2002. (c) Supply stacks from a large generation company in NSW for the month of June 2002. (d) Supply stacks from the same company on June 29, 2002.

To produce Fig. 6, we first divided prices into 5 price segments, which are those less than \$50/MWh, \$50–150/MWh, \$150–500/MWh, \$500–1000/MWh and \$1000–10000/MWh, and then aggregated the quantities in generators' daily bids with their corresponding price bands in the above price segments for the offpeak (04:30), shoulder (11:00) and peak (18:00) periods, respectively. If the quantity for a given price segment at the offpeak period is less (greater) than that for the same price segment at the peak period, then we say this generator increased (decreased) its capacity offers from offpeak to peak periods. Otherwise, the generator did not change its capacity offers from offpeak to peak. Similar calculations were made for the shoulder to peak period.

Fig. 6 shows that most generators did not change their quantities in the five price segments and some generators decreased their capacity offers from offpeak or shoulder periods to peak periods. This reduction of capacity happened more times from shoulder periods to peak periods than from offpeak to peak periods for the \$50/MWh price segment, which is the normal market price range. Even though the economic withholding of capacities (shift capacity from lower price bands to higher price bands) only happened occasionally, its consequence has been be enormous. For example, the extremely high price spikes in NSW during the winter peak season (see also Figs. 1 and 2) could be a result of capacity withholding.

Fig. 7(a), which shows the dispatch prices, dispatched generation and demand in NSW, depicts an example of this kind. The 5-min dispatch price in NSW on June 29, 2002 jumped from \$329.75/MWh at 17:25 to \$6108.11/MWh at 17:30, climbed even further to \$9874.78/MWh at 17:45, before finally coming down to \$324.15/MWh at 18:35.

The price spikes can be explained by looking at NSW's regional supply stack (a step function of quantity offers against price offers) in Fig. 7(b) and at the bids shown in Fig. 7(d) by one of the major generation companies in this region, where the supply stacks during the peaks shift more to the left compared to the shoulder periods before and after the peak in question. This particular company's total available capacity (of around 3790 MW) was offered to NEMMCO for almost all the settlement intervals in this period. This means that there was no outage of any of its generating units to cause the capacity reduction during the evening (super) peak period. Fig. 7(d) shows that this kind of capacity withholding is not just occasional. In fact it occurred consistently throughout the month of June 2002 (note that June is within the winter peak season in Australia). Fig. 7(c) shows that the company's offers for the selected settlement intervals corresponding to those in Fig. 7(b) are consistent with the regional supply scenarios for the settlement intervals.

Since the load shapes (e.g. the morning and evening peaks in summer and evening peak in winter) are well known to generators, they are more likely to withhold capacity during these peaks. How to monitor and prevent such bidding behaviours is an important issue to market designers and operators in general.

2.3.1. Shapes of bids

The shapes of bids from generating units provide important information about beliefs regarding market states and revenue expectations, because of the trade-off between volume of generation and market prices. In this subsection, we try to understand if there are any significant and persistent differences across generation technologies and the sizes of generating units. The figures all depict bids for the 17:30 settlement interval on June 28, 2002.

As shown in Fig. 8, most peaking gas units commit all their capacity to very high price bands even for this peak period and the large (base-load) units commit more than two-thirds of their capacities to very low price bands. Furthermore, due to the small sizes of peaking units, they use fewer increments to reach their capacities than the large units.

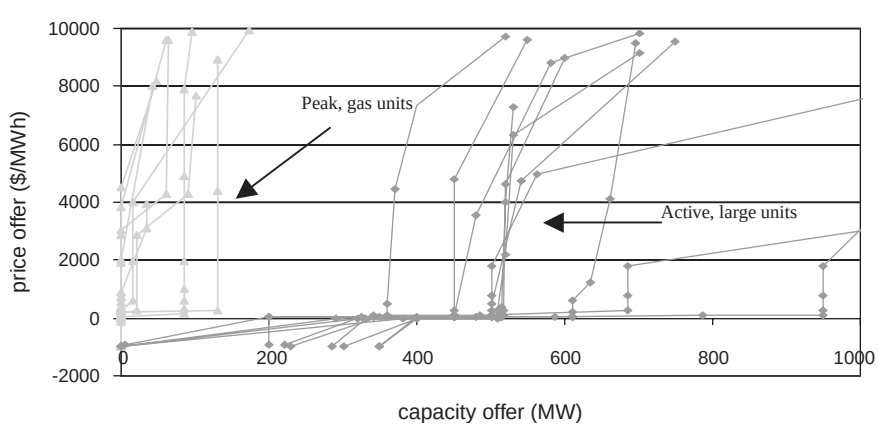

Fig. 8. Offer stacks from gas peaking units and active large units.

The large units commit parts of their capacities to negative price bands to ensure that they are dispatched in order to avoid the switch on/off cost or cover their contracted supply. Most of them reserved significant capacities for price bands close to the price cap.

Peaking units often shift their capacity to lower price bands via rebids when they see more profitable opportunities. For example, 4 out of the 8 peaking units made more than 1200 rebids during the study period based on economic reasons although they had less than 15% of the time in service. This bidding pattern can cause serious problems if the unit(s) is owned by a company who owns significant generation capacity. The company may well know the complete supply situation and can therefore affect the supply scenarios. The flexibility of peaking units gives it an even more powerful means of affecting market prices. This is another serious problem associated with the current rebidding policy in the NEM. Allowing this kind of rebidding may encourage more gaming behaviour in the market.

Although peaking units are entitled to reap the high prices due to shortage of generation capacities during peak periods, prices (in the order of thousand dollars per MWh as seen in Fig. 8) at which they are willing to generate are difficult to justify in terms of generation costs.

Fig. 9 shows the shapes of the bid curves used by small coal generating units. They commit (almost) all of their capacity to zero or negative price band(s). This is a common bidding pattern among this class of generator, although only the data for a particular settlement interval is displayed here. This pattern is rational because their smallness does not allow them much flexibility when facing competitors and uncertain demand. They need to secure a minimum generation level or bear uneconomical switching on/off costs. Consequently, their size prevents them from engaging in strategic bidding. The risks associated with switching on and off are huge. For example, the cost of the startup/shutdown of Duke Power's generation units in the United States (about 19 300 MW capacity, 48% of which is nuclear) due to weather forecasting errors is about US$8 million per year (see Keener, 2003). Note that large generating units are less exposed to such switch on/off risk due to variation of demand (see e.g. Brown, 2002).

2.3.2. Capacity factors

The *capacity factor* of a generator—which is defined as the ratio of the actual generation to its nominal capacity—also reflects its capacity strategy. The daily average capacity factors for the NSW and VIC regions for the period under review are shown in Fig. 10. For each dispatch interval, the ratio of dispatched generation to regional demand is calculated, and the average of the ratios over all (288) dispatch intervals within one day is referred to as the *generation sufficiency* of the region. The daily average *capacity sufficiency* is the average of the (48) ratios of the regional demand to the regional available capacity in each settlement interval within one day.

Large generation companies in different regions show very different capacity factors. Daily capacity sufficiency and generation sufficiency in NSW range from 1.08 to 1.3 and from 0.85 to 0.9, respectively; in VIC they range from 1.25 to 1.5 and 1.0 to 1.2. The higher daily capacity sufficiency in VIC may produce stronger competitive pressure on generators in VIC than in NSW. This is reflected by the daily capacity factors of the major generation companies in the two regions. In VIC, the capacity factors of the three major generation companies are around 1.0 and the fourth one has various capacity factors from 0.6 to 1.0 This contrasts with much lower capacity factors among the three major generation companies in NSW, which is a net power import region with a sufficiency of around 0.88 although the installed capacity in NSW is sufficient to meet demand almost all the time.

The extent of competition reflected by the capacity factors here is also echoed by the regional Herfindahl–Hirschmann Index (HHI) (see e.g. California ISO, 1999), which in our case is defined as the sum of the square of the ratios of an individual company's capacity

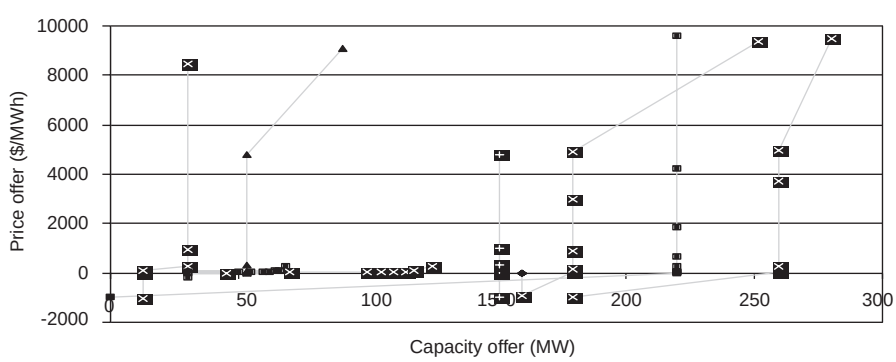

Fig. 9. Offer stacks from small coal units for the 17:30 settlement interval.

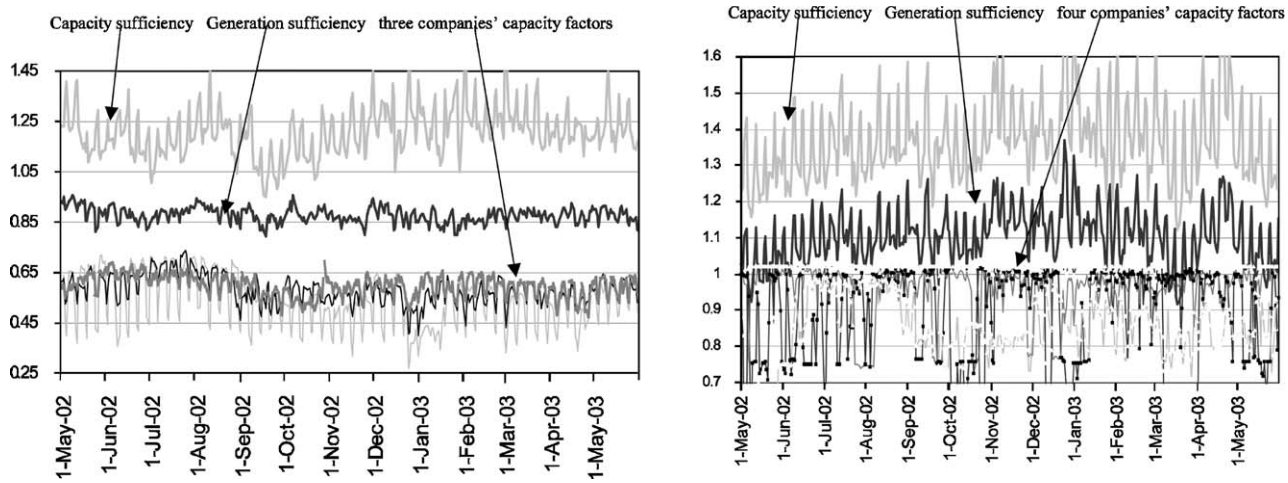

Fig. 10. Daily average capacity factors of major generation companies, capacity sufficiencies and generation sufficiencies in NSW and VIC respectively.

to the total regional capacity (in 10 000). The HHI for VIC is 1415, while it is 3097 for NSW. The HHI indicates that the generation assets are much more concentrated in ownership in NSW than in VIC and this higher concentration leads to a less competitive outcome.

The above observations suggest that a more efficient, competitive outcome may result if the large generation companies in NSW were broken into smaller ones.

2.4. Rebidding policy and its implications for bidding behaviour

We mentioned earlier that generators face volatile demand, and that demand forecasts at a decision point are not sufficiently accurate to plan their generation and unit commitment. Sometimes they overestimate the demand, and sometimes they underestimate it. Rebidding opportunities allow them to adapt or modify their decisions.

In the NEM, generators are allowed to rebid their capacity commitment in response to load changes, the generating units' physical limits, network status and ancillary service control status. More importantly, through rebids they can take advantage of the information provided by NEMMCO in the pre-dispatch phases to improve their revenue streams. There is considerable concern (see e.g. NECA, 2002) over rebids. Some argue that this process has been used by generators to exercise market power. NECA requires generators to submit a 'reasonable' explanation for their rebids and encourages them to make any rebids 'in good faith'.

Some peaking units frequently use rebidding to adapt to changes in market conditions, rather than using the daily offer/bid opportunities to cope with such changes. They offer identical quantity bands through all settlement intervals and then rebid at short notice. Moreover, these rebids can occur several times within a single settlement interval. This action emphasizes the volatility of demand and the rapidity of changes in market prices, which are not easy to predict and are compounded by the technical advantages of the fast-starting generating units.

There were 261 512 explanations for the rebids submitted by generators during the study period. We divided them into four categories: economic reasons, technical reasons, operating reasons and outside reasons. Economic reasons are defined as those where the rebids are made to improve financial position or for risk minimization etc.; technical reasons are those due to a failure of equipment; operating reasons are those due to O&M procedures such as (de)commissioning a unit and water management; while outside reasons are those beyond a generator's control, such as directions from market operators or network operators. This classification is based on keywords or phrases within the explanations. Examples of such keywords and phrases are given in Table 1. There are 27 474 explanations not classified. Most of these non-classified terms are either too vague to interpret or too specific to classify.

Irrespective of the (sub)period examined, economic rebids dominate the others (see Fig. 11). They represent nearly 50% of the total number of rebids. Moreover, it should be noted that some of the explanations in the other categories may amount to economic motivations. For example, outage plans may be used to change capacity commitment; transmission constraints may force generators to shift their quantity bands up or down.

Based on these rebid explanations, we may conclude that generators adjust their economic positions to adapt to market/environment changes. To strengthen the point, Fig. 12 shows that rebidding is much more intensive in peak periods (07:30–23:00, covered by

Table 1
Examples of keywords used to classify rebid explanations

Economic reasons	Technical reasons	Operating reasons	Outside reasons
Financial optimization, minimize cost, improve revenue, improve profitability, price/volume tradeoff, in response to pre-dispatch, manage generation portfolio, risk management	Condenser, filter, boiler, fan, vacuum, conveyer, damper, pulverizer, elevator, gear, switch, clinker valve, burner, actuator, ambient temperature, wet coal, fire alarm, seal leak, governor problem, ash problem	Unit testing, water management, dam/river/lake control, (de)commission, (re)synchronize, return to service, safety/energy/capacity/ramp operating limit, manual dispatch	NEMMCO direction, Powerlink direction, transmission constraints, Murray link, VIC-SA transmission link, Snowy-NSW transmission link

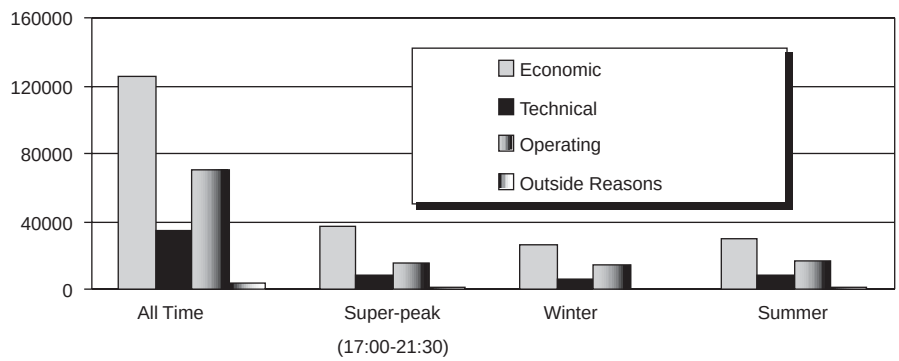

Fig. 11. Classification of rebid explanations.

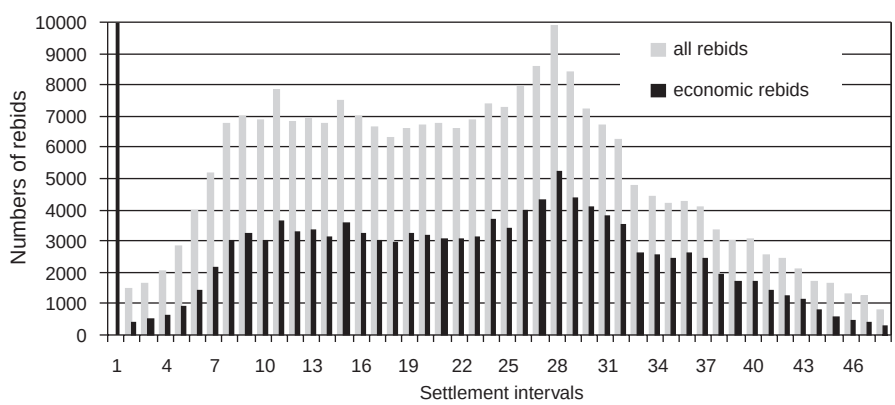

Fig. 12. Distribution of rebids and economic rebids over the 48 settlement intervals.

settlement intervals 7–38) than in the offpeak. The figure also indicates the same trend for economic rebids.

There are 86 coal, 22 hydro and 54 gas (plus oil) generating units, and the numbers of rebids made by these units are 1 28 499, 25 539 and 1 08 024, respectively. There are 34 generating units with capacities greater than 400 MW and they made 48 726 rebids over the study period (see Fig. 13).

The percentage referred to is the ratio of the number of rebids by all generating units using the same technology to that by all generating units. The per unit figure is the average number of rebids by each unit in the corresponding technology category.

Fig. 13 shows that the average number per unit of rebids made by gas turbine units is much greater than that by coal units. This may reflect the fact that gas turbines are more flexible than steam turbines, being able to adapt their generation level and availability quickly to changes in load. This flexibility allows them

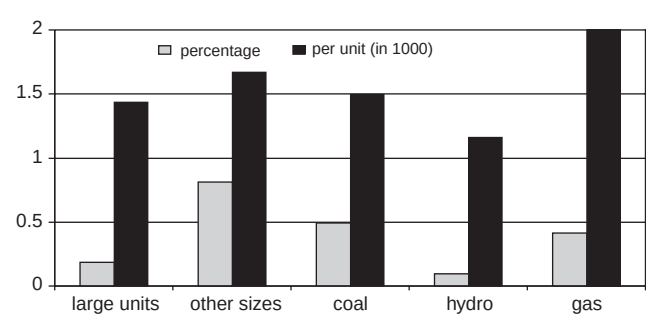

Fig. 13. Rebid distribution over units of different sizes and generation technologies.

to quickly change their generation levels in order to capture high prices. The hydro generators made fewer rebids than the coal generators, which may be due to their own energy constraints—although the hydro turbines are flexible.

Fig. 13 also shows that large generators, who own 54.1% of the total capacity, made fewer (1433 per unit) rebids on average than the remaining generators (1667 per unit) during the study period. The large generators provide base-load services and are less price-sensitive than small generators. On the other hand, large generators may be in a better position to foresee changing market conditions than small generators, because they have more plentiful resources to investigate market scenarios. However, these large generators (e.g. large coal units) made more economic rebids than small coal generators with capacities less than 400 MW (as shown in Fig. 14).

Fig. 14 shows that the number of economic rebids and total rebids made by gas units is much greater than that made by other type units. In fact, during the entire 13-month period, some units used less than three different price vectors and quantity vectors, while making over 3000 rebids and one unit, which made the highest number of rebids (5892), used only 43 price and quantity vectors in total.

The above statistics on rebidding raise several questions about the efficiency of the current policy governing rebidding within the NEM. First, it undermines the reliability and credibility of the daily bidding procedure, since many generators rely on rebidding even more than their original bids. Second, generators (both peaking units and base-load units) withhold capacity at high price bands and shift to lower price bands via rebids when market prices are sufficiently high. These rebids drive market prices artificially and unnecessarily high and send a distorted market price signal to participants, regulators and potential market entrants. Third, it reduces the reliability of the whole pre-dispatch process run by NEMMCO, since many generators have indicated (in their rebid explanations) that they shift their capacities between price bands to optimize their financial position in response to the pre-dispatch. Finally, rebidding increases the gaming opportunities for various players engaged in the bidding process.

3. Conclusions

We have studied the bidding and rebidding patterns displayed by generators in the NEM, based on publicly available bid and dispatch data for the period from May 1, 2002 to May 31, 2003. Several conclusions may be drawn from the data:

- There exist diverse behavioural patterns among the market participants, partially associated with different generation technologies, sizes and locations.
- Generators more frequently change their capacity offers to adapt to load variations.
- Scarcity of generation or transmission resources produces more price spikes in the various regions.
- Large generators have the ability to set and/or push market prices higher and display tendencies to withhold their capacities during peak periods.
- Generators take advantage of rebidding opportunities to optimize their financial positions in response to daily load changes, and other network and supply conditions.
- The current rebidding policy in the NEM has the implicit effect of setting market prices higher than they would otherwise be.

Bidding strategies have great impact on the market outcome and evolution of the market. There is a need for an efficient mechanism to increase competition among market participants and avoid adversary effects of strategic bidding or rebidding by generators who may abuse or take advantage of market rules and supply shortage during peak periods, as demonstrated in this paper. Strategic bidding by generators can push market prices higher during these peak periods because generators are sure of the supply and demand scenarios. If

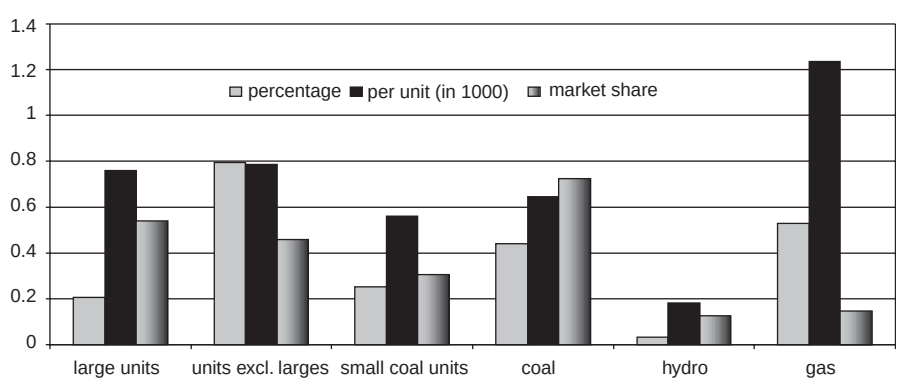

Fig. 14. Economic rebids over units of different sizes and generation technologies.

demand was responsive to market prices, generators would be less certain about any financial gains achieved by withholding capacity, thereby reducing the possibility of them exercising market power.

Finally, we believe that the complete market data provides sufficient posterior evidence to identify the frequencies and causes of market irregularities, such as excessively high prices and capacity shortages. It is even possible to use the database to examine capacity withholding behaviour associated with periods of high market prices, and to assess if generation companies have exerted market power. Thus, the revelation of data to the public imposes an appropriate degree of pressure on generators to behave more responsibly and competitively, especially if state and federal regulators use the data to scrutinize their market performance. Deregulated electricity markets do need more regulatory supervision of this kind.

References

Barmack, M.A., 2003. What do the ISO's public bid data reveal about the California market? The Electricity Journal 16, 63–73.

Borenstein, S., Bushnell, J., Wolak, F., 2002. Measuring market inefficiencies in California's restructured wholesale electricity market. American Economic Review 92, 1376–1405.

Brennan, T.J., 2003. Mismeasuring electricity market power. Regulation, Spring, pp. 60–65.

Brown, J.P., 2002. Quantifying volumetric risk—understanding the real risk of power plant options. The Risk Desk II (5), 1–2.

Bunn, D.W., Oliveira, F.S., 2001. Agent-based simulation: an application to new electricity trading arrangements of England and Wales. IEEE Transactions on Evolutionary Computation 5, 493–503.

California ISO, 1999. Market power and competitiveness. In: Annual Report on Market Issues and Performance, Market Surveillance Unit.

Keener, N.J., 2003. The estimated impact of weather on daily electric utility operations. *Duke Power Company*, Charlotte, NC (last visited October 20, 2003), http://sciencepolicy.colorado.edu/socasp/weather1/keener.html.

National Electricity Code Administrator (NECA), 2002. Bidding and rebidding: some ideas for a way forward.

North, M., Conzelmann, G., Koritarov, V., Macal, C., Thimmapuram, P., Vaselka, T., 2002. E-laboratories: agent-based modelling of electricity markets. American Power Conference Chicago, April, 15–17.

Outhred, H., 2000. The competitive market for electricity in Australia: why it works so well. Proceedings of the 33rd Hawaii International Conference on System Sciences, HI.

Short, C., Swan, A., 2002. Competition in the Australian national electricity market. ABARE Current Issues, January, 1–12.

Wolak, F.A., 1999. An empirical analysis of the impact of hedge contracts on bidding behaviour in a competitive electricity market. Stanford University, March.

Wolfram, C.D., 1999. Measuring duopoly power in the British electricity market. American Economic Review 89, 805–826.