



# **Assessment of proposed energy trader scheme in NSW**

Report on the effects of the proposed energy  
trader in NSW on the operation of National  
Electricity Market and electricity consumers

Prepared for the Energy Users Association of Australia

**1 October 2004**



**ACIL Tasman**

Economics Policy Strategy

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## Executive summary

This report identifies, discusses and assesses the various impacts of proposed energy trader scheme (the Scheme) in New South Wales (NSW) on the National Electricity Market (NEM) and on electricity users in NSW and elsewhere. Where possible, electricity market modeling has been used to quantify the impacts.

### Findings

The success of the Scheme, from electricity users' perspective, will critically depend on:

- having at least five and not three generation portfolios;
- fostering development of a deeper financial hedge market by placing a limit on the paring of generation traders with retail managers;
- improving retail competition by awarding the retail manager contracts to no less than three separate competing retailers of a reasonable size;
- ensuring ongoing market discipline is applied to the power station operation through appropriate conditions in the generator trader contracts;
- the NSW Government striking an appropriate balance between returns as owners of the electricity assets and delivering lower electricity prices;
- ensuring that coal prices are appropriately considered in offers to the NEM by private generator traders;
- incorporating demand management (DM) as part of the tender evaluation process;
- developing a clear tender evaluation and selection process to be known up-front by bidders; and
- development of a more of a robust methodology to avoid a hedge contract hiatus occurring as the five year generator contracts expire.

### Market modeling of the Scheme

The possible market impacts of the Scheme have been analysed using ACIL Tasman's electricity market model – *PowerMark*.

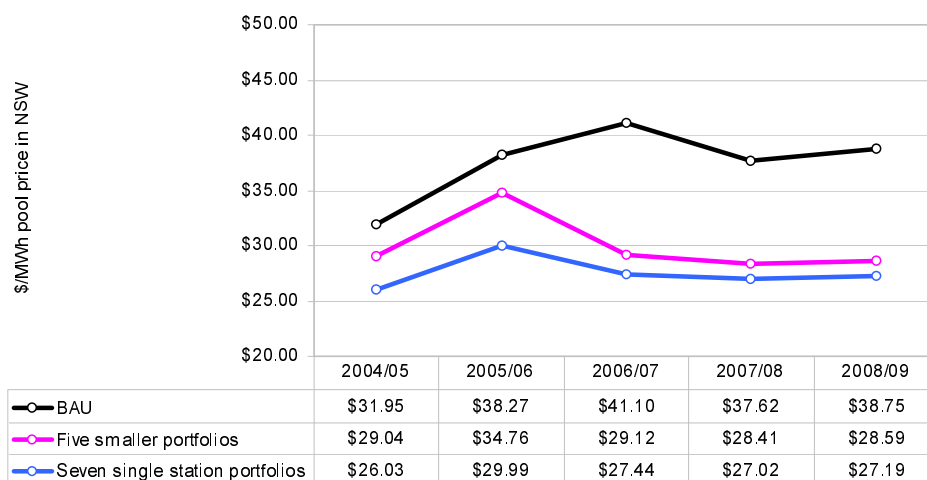
The scenarios modeled are:

- Business as usual (BAU) - used as a reference case and assumes the Scheme is not implemented;
- Zero marginal cost – to quantify the effects of the periodic payments for coal assuming that, in response, private traders offer contracted capacity at zero;

- Lower contract cover – to study the market power available to private generator traders under a three portfolio structure, by estimating the increase in pool prices resulting from traders reducing contract levels and gaming the market;
- Five and seven portfolios- to assess the extent of reduction in market power provided by moving to a five or seven portfolio structure by estimate the reduction on pool prices involved; and
- Five and seven portfolios with lower contract cover – to evaluate the level of protection from generator market power offered by a five or seven portfolio structure, by quantifying the ability of portfolios to influence pool prices by reducing contract cover.

The modeling clearly demonstrates that there is a significant potential benefit from the Scheme by moving to structure with at least five generation portfolios as illustrated in Figure 1.

Figure 1 **NSW pool prices under different portfolio structures**

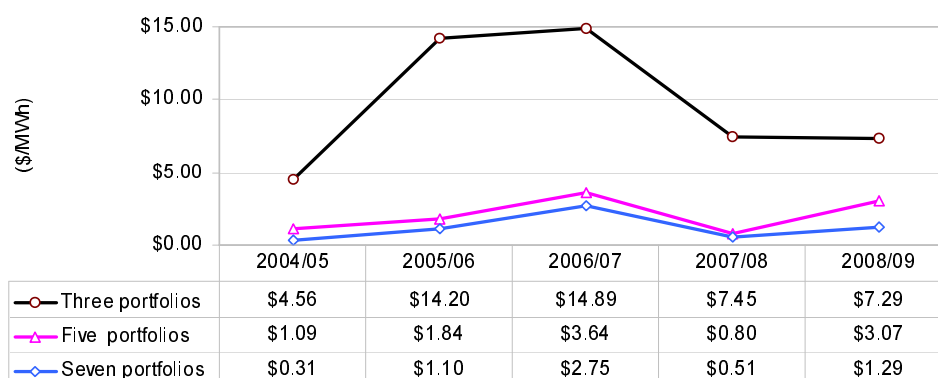


Data source: PowerMark modelling

This large reduction in pool price by moving to a five portfolio structure, highlights the degree to which the current three portfolio structure keeps prices artificially high over the projection period.

A structure with five or seven generation portfolios reduces the ability of any one portfolio to profitably game the market. Figure 2 shows that, with a five portfolio structure, a five percentage point reduction in the largest portfolio (Bayswater) increases price by far less than under the BAU where MacGen can have a significant impact on price. The added protection against use of market power of moving to a seven portfolio structure is minimal.

Figure 2 **Increases in the NSW pool price from reductions in contract cover in the largest portfolio, under different portfolio structures**



Data source: PowerMark modelling

## Recommendations

The following 13 recommendations show how the key features of the Scheme would need to be addressed in order for the scheme to be acceptable to electricity users and to preserve the critically important characteristics of the competitive market.

- Recommendation 1. At least five (not three) generation portfolios be offered to private generator traders to mitigate potential market power.
- Recommendation 2. Reserve prices to be kept secret and set to achieve an appropriate balance between auction returns and competitive electricity prices not just to maximize government returns.
- Recommendation 3. All existing and new coal contracts should be under the total control of the private retail trader, with any new contracts extending beyond the expiry of the trader contract to be approved by government and pass back to the government at expiry of the generator trader contract.
- Recommendation 4. Encourage ongoing increased efficiency in the power station operation in the generator trader contracts, with appropriate incentives and penalties payable by and to the generator trader.
- Recommendation 5. To foster the development of a deeper financial hedge market, a limit should be placed on the amount of generation capacity which can be paired with retail traders.

- Recommendation 6. In recognition of the importance of retail competition, the Scheme should award the retail management contracts to no less than three separate retailers.
- Recommendation 7. Further detailed consideration be given to the likely adverse effects on the hedge market of the expiry of the five year generator trader contracts; and develop and publish mitigation strategies before proceeding with the Scheme.
- Recommendation 8. Provide an option for contract customers to transfer to a retailer of choice, if there is unsatisfactory performance by the chosen private retail manager.
- Recommendation 9. Provide, up-front, the rules which will govern the letting of the trader contracts, including the process to be used to compare bids.
- Recommendation 10. Clearly define the approach to be taken with transfer of greenhouse gas abatement contracts.
- Recommendation 11. That the tender documents for the generator trader and retail manager contracts incorporate a request for bidders to outline the DM strategies that they intend to adopt and that these responses be given an appropriate weighting in the bid evaluation process.
- Recommendation 12. Ensure that DM is adequately addressed in the proposed NSW SOO by including an assessment of DM opportunities and appropriate incorporation in the load forecast.
- Recommendation 13. Consideration should be given to applying the ETEF funds to encourage greater DM by state-owned retailers.

# 1 Introduction

The Energy Users Association of Australia (EUAA) has engaged ACIL Tasman to undertake an assessment of the impacts of the proposed energy trader scheme (the Scheme) in New South Wales (NSW) on the National Electricity Market (NEM) and on electricity users in NSW and elsewhere. The report has been funded by a grant from the National Consumers Advocacy Panel of the National Electricity Code Administrator (NECA) and is to provide the foundation for a submission to the NSW government on the Scheme from the EUAA on behalf of electricity users..

The report identifies, discusses and assesses the various aspects of the Scheme, which are likely to impact the NEM and electricity users, and where appropriate, uses market modeling to quantify the impacts.

ACIL Tasman's *PowerMark* model of the NEM has been used to evaluate the possible price and other effects of the Scheme. *PowerMark* is a market simulation model, which produces hourly regional reference prices (pool prices) and station dispatch. In the model, generation portfolios are optimised using a Nash equilibrium approach and settled using a linear program similar to that used by the National Electricity Market Management Company (NEMMCO).

## 2 Outline of the Scheme

### 2.1 Background

A Discussion Paper on the proposed energy trader scheme (the Scheme) entitled “A Risk Management Proposal for New South Wales, Electricity Businesses” was first released by the NSW Government in December 2001. A Further Discussion Paper with the same title was released in May 2004. It is this Further Discussion Paper, which is being evaluated in this report.

The stated aim of the Scheme is to transfer, through a contract auction arrangement, the financially high-risk task of wholesale electricity trading, from the state-owned generators and retailers to the private sector. The Government would retain the ownership and operational control of the power stations. The Government believes that the scheme will substantially reduce electricity market risks for taxpayers.

#### 2.1.1 Key elements of the Scheme

The Scheme as outlined in the Further Discussion Paper has the following two key elements:

- contracting-out to private *generator traders*, the market trading elements of each of the three state-owned generation corporations; and
- contracting-out to private *retail managers*, the market trading elements of each of the state-owned retail corporations including transfer of the retail management of all contracted (or negotiated) customers to the successful private retail managers.

### 2.2 Trader contracts

The Scheme, if implemented, would see the letting of a series of generator trader and retail manager contracts to the private sector. These contracts would see the capacity of the state-owned generators being offered into the NEM by private generator traders and the retail market hedge trading and contracted retail customer operations of the state-owned retailers transferred to the private retail managers.

#### 2.2.1 The auction process

As currently envisaged the awarding of generator trader and retail manager contracts will be based on a simultaneous, combinatorial auction process with

a preference for tendering out generation and retail rights at the same time. This would allow private traders to bid for combinations of generator trader and retail manager contracts (subject to any *Trade Practices Act* issues) and maximize the value of the auctions.

### 2.2.2 Reserve price

Prior to the auction, the government would set reserve prices for each trader contract. It is not absolutely clear from the Further Discussion Paper how this will be done. It seems that the reserve price would either:

- reflect the (risk-adjusted) value of retaining the trading rights; or
- cover the costs of electricity production and delivery and to meet the public sector's anticipated earnings from trading, adjusted for the reduction in risk.

### 2.2.3 Contract term

The initial trader contracts would be for a term of five years. If continued, replacement generator trader contracts would be tendered well in advance of the expiry of the initial trading contracts to minimise any resulting discontinuities in the electricity hedge market.

### 2.2.4 Responsibility for existing contracts

Ultimate responsibility for existing coal, market hedge and retail customer contracts would remain with the state-owned businesses but be administered by the private traders through “mirrored” contracts. Any new coal, market hedge or retail customer contracts entered by the traders will remain the responsibility of the energy traders even after expiry of the trading contracts.

## 2.3 Electricity user considerations

The rights of retail customers and the responsibilities of state-owned retailers under existing retail sales contracts are preserved with the private retail managers providing retail services under retail agency agreements. However, customers will be forced to accept the successful retail managers as their retailers until expiry of the existing retail sales contracts with the state-owned retailers. The view expressed in the Further Discussion Paper is that the private retail managers have a strong incentive to retain the contract customers by providing high quality services.

Small customers choosing to remain on regulated electricity tariffs will continue to receive retail services from the state-owned retailers supported by the Electricity Tariff Equalisation Fund (ETEF). Under the Scheme the

generator traders would be responsible for topping up the ETEF when required.

## 2.4 Generator trader

The current preferred position is to have three generator traders linked to the three existing state-owned generation portfolios, but the option of having more generator traders with less generation capacity has not been completely ruled out. However, regardless of the generation portfolios offered to the private generator traders, the three state-owned generation corporations will be retained to own and operate the power stations.

### 2.4.1 Pricing structure

The price to be paid under the generator trader contracts will consist of three elements:

- a fixed periodic payment for access to the generation capacity;
- a periodic payment to cover generator costs of coal contracts; and
- periodic payment to cover running costs agreed up front and paid on a fee-for-service basis.

### 2.4.2 Treatment of fuel supplies

The preferred option for fuel supply is that:

- The state-owned generators continue contracting with coal companies for longer-term supply beyond the term of the generator trader contracts because, it is argued, they have a strong incentive to keep coal costs low because the future of the power station will be determined by whether private traders believe the plant is competitive.
- The private generator traders take responsibility for existing coal supply through coal supply contracts which mirrored the existing coal supply contracts in aggregate and make periodic payments to the state-owned generator to cover the existing coal contract costs.
- The private generator traders have responsibility for arranging short-term fuel purchases, although the traders would remain responsible for any coal contract still in effect at the termination or expiry of their generator trader contracts.

An alternative to the mirror contracts for managing existing coal contracts identified in the Further Discussion Paper, is to require the private generator trader to bid each generation portfolio to dispatch a minimum monthly volume of electricity that matches the volume of contracted coal supplies for that month.

## 2.5 Retail manager

The Scheme involves auctioning the wholesale trading operations of each of the state-owned retailers along with the retail management of their contract (or negotiated) customers. It is currently expected that these auctions would be held at the same time as the generator trader auctions to provide the private bidders with the opportunity to bid for a combination of generator and retail traders.

The private retail managers would assume responsibility for providing retail services to the contracted customers under retail agency contracts with the state-owned retailers. However, the state-owned retailers would remain the legal counterparties until the existing retail supply contracts expire.

The retail agency contracts would prescribe minimum service standards for existing contract customers. In addition, the private retail managers would need to be licensed NSW retailers so they would have to comply with additional customer protection measures including a customer code of conduct, a requirement to disclose minimum billing and charging information and an obligation to adopt customer dispute resolution procedures.

At expiry of the retail manager contracts, the private retail managers retain all contracts current at that time. This suggests that, apart from a small number of existing long-term retail customer contracts which have not expired, the government will no longer have control of the retail manager businesses. It is not clear from the Further Discussion Paper how the government will be in a position to re-auction these retail manager businesses. However, the Government would appear to have left open the option of the state-owned generators and/or retailers buying back the long term hedge and other contracts from the private traders at expiry of their trader contracts.

### 3 Issues raised by the Scheme

There are many possible implications for electricity users emanating from the Scheme. The key among these is the possible changes in approach private generator traders are likely to implement in offering the power stations into the NEM and negotiating hedge contracts with retail managers. These activities could result in an increase in wholesale prices and ultimately an increase in electricity prices to consumers particularly if the existing three generation portfolios are offered intact. One option available to private generator traders would be to reduce the level of contract cover to free-up capacity which could then be strategically withdrawn to support higher regional pool prices. This key aspect of the scheme has been quantified using market modelling as discussed in Section 4.4.3.

Currently NSW is a large net importer of power from Queensland, Victoria and Snowy even though the capacity factors being achieved by its base load, coal fired power stations are generally lower than the Queensland black coal stations and the Victorian brown coal stations. A private generator trader, in attempting to support higher pool prices, would be unlikely to increase dispatch from the NSW stations particularly if the price paid for the capacity is relatively low based on current low dispatch levels. As such there will be a greater probability of generally higher prices and perhaps even an increased chance of price spikes.

The Scheme should not lose sight of the fact that a market incorporating retail contestability combined with genuine competition among generators offers the best chance for achieving the lowest possible electricity prices while, improving service quality. This does not add to consumer risk but minimises it. The question for the NSW Government should be whether people and businesses gain a greater consumer surplus through lower electricity prices as electricity consumers, or through higher returns from state owned generators and retailers as taxpayers. The build up in ETEF clearly shows, for example, that regulated tariffs are higher than the market would deliver to consumers.

#### 3.1 Overall issues

The NSW Government has a serious conflict of interest, which could potentially act against the interests of electricity users. On the one hand, it is keen to provide enhanced returns for its power stations by extracting as high a price as possible for the generator traders and retail manager contracts, while on the other hand, it is keen to foster competitive electricity prices.

Furthermore, unlike the NEM, the Scheme does not seem to be concerned with providing improved prices and quality of supply to electricity users, but is focussed on reducing Government electricity market risk exposure.

The Further Discussion Paper asserts that the Scheme's primary purpose is to transfer market risk from the public to private sector, which is best equipped to manage these market risks. It is acknowledged that a carefully balanced assessment and management of risks has potential to deliver benefits to consumers through lower prices. A risk averse approach, which is probably more likely to be pursued by government, is likely to result in higher prices to consumers as government entities seek to cover off all possible risks regardless of how remote the possibility of them occurring.

The Further Discussion Paper does not provide a discussion of the various NEM participant risks but recognises that the prices offered by private parties for the generator traders and retail managers will incorporate an allowance for the risks involved. The Government will only be better off if it has a higher aversion to risk than that the private bidders.

In fact, market price risk can be managed by financial hedges provided that appropriate counterparties are available for wholesale energy trading. By allowing a private party to gain control of both generation capacity and retail customers is likely to reduce the depth of the financial market, making it more difficult to find suitable contract counterparties thereby exposing market participants to greater price risks.

An effective financial hedge market is characterised by narrow buy/sell price spreads and this is only likely to be achieved if the market has sufficient depth as determined by market size and number of transactions. The effective withdrawal of large quantities of generation capacity from the financial hedge market, as is likely if a private party gained control over generation capacity and retail customers, is likely to result in increased buy/sell price spreads, less trading, greater price volatility and potentially higher prices.

The balance between supply and demand in the NEM is a critical risk factor for participants and the Scheme will not alleviate this risk for the Government as owner and operator of the generation capacity. No participant has control over this risk factor.

Equipment reliability (generation, transmission and distribution) can be a risk factor, but generally it can be managed by sound management and maintenance practices. The Scheme, however, attempts to remove the state-owned generators from the rigours of the market and, as such, in the opinion of many increases the risk of plant failure.

### 3.1.1 Market power

The possible exercise of market power is a real concern to electricity users if, under the Scheme, the capacity of each of the three large state-owned

generation portfolios in NSW is transferred intact to the private sector. This has potential to be raised as an issue under the *Trade Practices Act* (TPA) as it may be seen as having potential to result in higher electricity prices than would have occurred in a more appropriate competitive environment. The market power problem for consumers would be exacerbated if the winning bid was from an existing generator in another state, particularly if the TPA cannot be relied upon to provide adequate protection for electricity users.

It would be unfortunate if the NSW Government, in seeking to maximise the price for access to its generation capacity, does not give serious consideration to splitting the generation portfolios in order to enhance the outcome for electricity users.

Keen competition among retailers is a critical element in achieving desirable market outcomes for electricity users. Retail market power whether through number and/or size of retailers, retailer links with generation or relationships between retailers and distributors has not been addressed adequately in the further Discussion Paper and will need careful consideration in assessing the successful retailers. A key element of the Scheme should be to ensure enhanced competition among retailers so that retail margins are kept in check and there is a strong incentive for retailers to keep wholesale prices as low as possible. Finally, a market where there are a reasonable number of retailers, certainly not less than three, provides a good platform for the further deepening of financial markets which are so essential for retailers and generator traders to manage their market risk exposure.

### 3.1.2 Vertical integration of generation and retail

The combinatorial auction process is likely to result in the one private sector entity gaining control of both a generator trader and a retail manager. Because of the obvious synergies in having control of both significant generation capacity and a large section of the retail market, private bidders can be expected to bid higher prices for these combinations of assets rather than as individual businesses and this in turn would naturally be attractive to the NSW Government.

This situation is common in the United Kingdom but not in Australia. It is likely to impact on how the generation capacity is offered into the NEM. However, provided there is sufficient generation and retail competition and the price paid for the trader and retail businesses is not excessive, the combination of generation and retail could well benefit electricity users by delivering lower pool and hedge contract prices by removing the need for much of the trading operation.

On the negative side for electricity users, allowing combined generation and retail businesses would reduce in the depth of the financial hedge market with the combined generation retail businesses opting to carry their own internal price hedging arrangements. This reduction in depth of the financial hedge market will increase the price risk for other retailers without generation because competitive hedge contract counterparties will be more difficult to find and hedge contract prices are likely to be higher.

This is not good news for electricity users as it will reduce competition in both generation and retail markets and is likely to result in higher, less stable electricity prices.

### **3.1.3 The auction process**

The simultaneous combinatorial auction process has the potential of delivering unacceptable level of market power to private traders to the possible detriment of electricity users. This would emerge as a result of the government seeking to maximise its financial position from the auction. There is also the risk that the cost of winning the generator trader and/or retail manager contracts will result in higher prices for electricity users as private traders seek to recover these costs.

The auction process, as described in the Further Discussion Paper, allows multiple bids for any combination of generator traders and retail managers which is likely to be problematic for government with many possible bid combinations potentially raising serious probity issues. Because there is a large number of possible combinations of retail managers and generator traders which could attract bids, the Government will need to clearly explain up-front how it intends to select the winning bids to ensure that no legal action is taken by unsuccessful bidders after the winning bids are announced. Such legal challenges could well drag on for many months creating uncertainty and perhaps higher prices which would be an unacceptable outcome for NSW electricity users.

For example, assuming there were only two generator traders (G1 and G2) and two retail managers (R1 and R2) available either separately or in combination and the following eight highest bids were received:

- Bid 1: G1 on its own (highest bid for G1)
- Bid 2: G2 on its own (third highest bid for G2)
- Bid 3: R1 on its own (second highest bid for R1)
- Bid 4: R2 on its own (second highest bid for R2)
- Bid 5: G1 paired with R1 (third highest bid for G1 and highest bid for R1)
- Bid 6: G2 paired with R1 (second highest bid for G2 and third highest for R1)

- Bid 7: G1 paired with R2 (second highest bid for G1 and highest for R2)  
 Bid 8: G2 paired with R2 (highest bid for G2 and third highest for R2)

There are seven possible combinations of winning bids as follows:

- Combination 1: Bids 1, 2, 3 and 4 (ie G1, G2, R1, R2 separately)  
 Combination 2: Bids 1, 3 and 8 (ie G1, R1 separately and G2&R2 together)  
 Combination 3: Bids 5, 2 and 4 (ie G1&R1 together and G2, R2 separately)  
 Combination 4: Bids 5 and 8 (ie G1&R1, G2&R2 together)  
 Combination 5: Bids 7, 2 and 3 (ie G1&R2 together and G2, R1 separately)  
 Combination 6: Bids 1, 4 and 6 (ie G1, R2 separately and G2&R1 together)  
 Combination 7: Bids 6 and 7 (ie G1&R2, G2&R1 together)

Regardless of which combination is accepted there will be disgruntled bidders unless the selection process is clearly enunciated by the Government at the outset. For example, if Combination 3, where Bids 5, 2 and 4 are the winning bids, were chosen because it offered the highest overall return to the Government, then the disgruntled bids would be:

- Bids 1 and 7 with higher bids for G1,
- Bids 6 and 8 with higher bids for G2 and
- Bid 7 with a higher bid for R2

This is a complex issue which is identified in the Further Discussion Paper but has not been adequately addressed. The Scheme should not be implemented until a satisfactory selection methodology is established and well known to the bidders.

## 3.2 Generator trader issues

There are a number of issues specifically linked to the generator trader concept, which have the potential to result in higher pool and hedge contract prices to the disadvantage of electricity consumers.

### 3.2.1 Portfolios and market power

Passing control of the generation capacity of each of the large generation portfolios such as Macquarie Generation (MacGen) and Delta Electricity (Delta), to individual private generator traders has potential to provide the traders with unacceptable market power. Government ownership of these

large generation portfolios currently seems to generally restrict the use of market power by these corporations.

The market power concerns would be addressed by offering smaller parcels of generation capacity, such as individual stations, to each private generator trader rather than each of the three generation portfolios as they currently exist. This approach is also likely to open the market to a greater number of existing generator traders as they more likely to be able to add smaller increments of capacity to existing capacity without raising TPA issues. There seems little doubt that the ACCC would, for example, resist any one of the large private Victorian brown coal generators gaining control over say all the MacGen capacity rather than one of the two stations in this portfolio. This means that the number of available bidders would be substantially less if the three portfolios are offered intact.

### **3.2.2 Compensation for generator failure**

The generator trader contracts could be expected to incorporate arrangements for compensation should a generator suffer a catastrophic failure and the associated private trader is unable to service its market hedge contracts. These compensation payments will add to the cost of producing electricity, which will be to the ultimate cost to consumers.

Should such a failure occur under the current situation where the government controls all aspects of electricity generation, then arrangements could be made to simply transfer responsibility for providing generator backup for hedge contracts to another generation portfolio which has spare capacity without significant cost to the consumer.

### **3.2.3 Market discipline on generators**

Probably the most disappointing aspect of the Scheme for electricity users is that the cost discipline imposed on generators by a competitive market is likely to be significantly reduced. Under the Scheme, generator operating and fuel costs will be fully covered by periodic payments under the generator trader contract leaving little incentive to strive for further efficiency gains and cost reductions. The fixed fee for access under the generator trader contract, arrived at through the competitive auction process, can be expected to be based on an assessment of the generators' market value. However, weather or not this fixed access fee is sufficient to cover fixed costs and a reasonable return to equity holders, it is not likely to impose any commercial discipline on the state-owned generator operator in terms of managing the generation plant.

A further example of the lack of discipline on the state-owned generators is that the Scheme requires state-owned operators to only maintain existing levels of reliability, not improve them.

### 3.2.4 Fuel supply and market trading

It is difficult to see how a trader will be able to effectively trade generation capacity in the market without having full control of the fuel supply arrangements. Matching fuel supply arrangements to offer strategies is a critically important aspect of trading in the market. It also provides a strong incentive on the generator to seek lower cost fuel supplies. Furthermore, when these market disciplines apply, coal quality characteristics are correctly considered in a commercial rather than purely operational setting, as they would tend to be treated under the Scheme.

While allowing power stations to continue to arrange longer term fuel purchases should achieve the governments objective of ensuring that a continuous supply of coal is available for the power stations, it will be done in a non-commercial setting and is likely to result in non-competitive supply arrangements which would not allow effective offering of the station into the NEM.

### 3.2.5 Three tier pricing

As shown in Section 2.4.1, the price to be paid for generator traders will consist of three elements:

- a fixed periodic payment for access to the generation capacity;
- a periodic payment to cover generator costs of for coal contracts;
- periodic payment to cover running costs agreed up front and paid on a fee-for-service basis.

The three tier pricing structure for the generator trader contracts has potential to distort the offer strategies of the private traders but could result in lower average pool prices especially in the low load period overnight when a higher proportion of the load is contracted. This, in turn, would change flows on the interconnectors resulting in reduced net flows into NSW and improved capacity factors of the NSW power stations.

The three tiered pricing structure currently proposed, by incorporating a periodic payment to cover the cost of existing coal contracts which, assuming it is not linked to coal usage, is likely to mean that private generator traders treat the periodic fuel payment as a sunk cost not contributing to the short run

marginal cost (SRMC)<sup>1</sup> of the station. If this occurs then generation based on this coal would be regarded as having a SRMC close to zero. This, in turn, would allow close-to-zero price offers into the NEM for that component of capacity covered by hedge contracts.

This offer strategy would result in lower pool prices and hedge contract prices, which should be reflected in lower prices to electricity users, but would tend to be offset by increased dispatch by the NSW stations. This occurs because the increased dispatch is of generation capacity beyond the contracted level in the competitive portion of the generator offer curve thereby allowing the NSW generatios generator traders more opportunity to game the market and force up prices.

### **3.2.6 Market approach**

The main driver for all three government owned generation portfolios early in the market, when forced vesting contracts provided a high level of contract cover and financial security, was maintaining or increasing market share at the expense of pool price as income was largely guaranteed under the forced vesting contracts. As vesting contracts fell away, with increased contestability and contracting becoming optional, a contracting hiatus developed with retailers preferring to rely to a large degree on supply from the pool given the suppressed pool prices.

Generator offer strategies then gradually changed in an attempt to rescue the pool price. Initially these strategies were moderately successful, particularly while contracting levels were subdued, and pool prices began to increase.

Contract levels then surged, particularly in Victoria and South Australia, where hot summer conditions in 2000/01 combined with plant outages, exposed retailers to price spikes. The higher contract cover which developed left less opportunity for generators to game the market and pool prices again began to reduce.

In the current phase of the market, with contract cover at reasonably high levels, with the addition of over 2000MW of new, low cost capacity in Queensland and development of the Queensland to NSW interconnector (QNI), prices have caused NSW pool prices to slump further. The SNOVic interconnector expansion and the addition of peaking capacity in Victoria and SA have also been contributing factors to the recent low NSW pool prices but not nearly as significant as QNI and the new low cost base load plant in Queensland.

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<sup>1</sup> The SRMC is the fuel cost plus variable O&M assuming fuel is not all take-or-pay.

This rather tumultuous learning phase of the NEM, has prompted the NSW Government owners to seek ways of increasing profitability in the market setting. Establishment of the ETEF is often seen as one way the Government has attempted to improve the financial performance of its generators. The generators themselves have also been active in trying to improve their financial performance through market trading approaches. The price spikes caused by the NSW generator offers stimulated in response to the significant build-ups in the ETEF (see Section 3.2.8) showed that generators can and will influence the market to enhance financial performance if the incentive is strong enough.

The approach being taken by each of the three government-owned generation portfolios to the market realities is somewhat different.

MacGen has been attempting to improve its market position by aggressively pursuing lower coal prices and improving station thermal efficiencies.

Delta has also adopted strategies to improve its positioning in the market by coal purchase strategies but these have been severely limited by high priced long term coal supply contracts from Centennial coal (purchaser of the state-owned PowerCoal), which still have many years to run and have been renewed and extended as part of the sale of PowerCoal.

The opportunity for Eraring Energy to reorganise its very high cost coal supply have even been more limited. However, Eraring does not seem to have seriously attempted to increase its poor capacity factor by organising additional, lower cost fuel supplies. The approach currently being followed by Eraring is probably also linked to cooling limitations of Lake Macquarie.

The current fuel supply and other limitations on the NSW coal fired power stations will initially confront any private energy trader, but their market response may well be somewhat different to that of the existing government owned generators given the significantly stronger commercial imperatives for the private trader. The approach taken by private generator traders will hinge to a large degree on the price paid for access, the terms and prices of the inherited hedge contracts, and the size of generation portfolios offered at auction.

One clear option available to a private trader would be to reduce the level of contract cover and attempt to game the market to force up pool and hedge contract prices. The larger the capacity available, the lower the contract cover, and the lower the take-or-pay coal quantity, then the greater the ability of private traders to effectively game the market and move pool prices upwards.

The main obstacles working against this strategy are the current excess supply of generation capacity and possibly the price and take-or-pay volume of coal. In this regard, a private trader with access to the large MacGen capacity with

its lower coal prices, would be in the best position to influence the market and achieve higher pool prices.

### 3.2.7 Contract term

It is difficult to envisage a seamless hedge contracting market under the proposed five year term for the generator trader contracts, even with the next five year period trader contract let well in advance as envisaged in the Further Discussion Paper. This is because incoming traders will not wish to enter a heavily hedged position before they develop an in-depth understanding of the market and have at least some experience with offering the capacity into the market and the capability of the generator operator.

A short term decline in the availability of hedge contract cover is very likely as the expiry of the generator trader contracts approach expiry. In this setting, retailers will find it increasingly difficult to arrange market hedges, which allow them to provide the retail contract terms and conditions that will be satisfactory to consumers.

These increases in price and volatility are not good for electricity consumers, particularly in NSW, seeking stable and competitive electricity supply arrangements.

### 3.2.8 Treatment of the ETEF

The ETEF is a significant market distortion, which may have greater potential to cause higher pool prices in the NEM under the Scheme where private generator traders have control of NSW generating capacity, than under existing arrangements.

Currently the ETEF accounts for around 30% of the NSW electricity demand (on average), which is lower than the 38% share when the ETEF commenced in 2001. Under the Scheme, the private generator traders will be required to meet the current generator obligations of topping-up the ETEF when necessary, based on the dispatch from the generators in their control and the prevailing pool prices.

This means that the private generator traders will need to consider this ETEF obligation when making offers to the NEM and in considering the proportion of capacity to cover with hedge contracts. In fact, it would not be logical for the private generator traders to carry hedge contract cover for the ETEF portion of capacity. This is to ensure that they recover the full pool revenue for the ETEF portion of their capacity when dispatched. It is particularly important when payments into the ETEF could be required by the private

generator traders following a period when pool prices are above the ETEF regulated energy cost (REC) and the funds in the ETEF are depleted..

In effect, the ETEF is a market distortion which, by reducing the contract cover carried by private generator traders, will allow greater freedom for them to game the market to achieve higher pool prices. This is because the private generator traders will have a greater portion of available capacity, which is able to be offered at prices above SRMC<sup>2</sup>.

In fact, the NSW state owned generators generally treat the ETEF portion of their dispatch as though that portion of their capacity is covered by hedge contracts and offer it at, or close to, their SRMC. However, there have been two occasions when the fund had built to a substantial size of over \$300 million because average pool prices had been lower than the REC for some months, when the state-owned generators adjusted their offers to the NEM at critical ramp-up times and caused pool price spikes until the ETEF balance was substantially reduced, in one case to less than \$10 million.

We expect that private generator traders will offer the ETEF component of their capacity at somewhere between their SRMC and the REC. It seems reasonable that the lower the funds in the ETEF, then the closer the offer price for the ETEF component of their capacity will be to SRMC so as to produce pool prices less than the REC and allow the size of ETEF to naturally build. When ETEF contains substantial funds then the offer price for the ETEF component of capacity is likely to be closer the REC. Depending on the trader portfolio structure used in the Scheme, private traders may have the market power to claw back funds from ETEF by causing price spikes in a similar way to the state-owned generators, although such action is likely to be closely scrutinised by the regulator, as they were when first undertaken by the state-owned generators..

### **3.3 Retail manager issues**

#### **3.3.1 Retail structure and market power**

The relative size and number of retailers is a factor which needs to be carefully addressed in the awarding of the retailer manager contracts. While barriers to entry are not as significant for retailing as for generation, it is nevertheless important that there be competition among retailers so retail margins are not excessive and the lowest possible wholesale price is delivered to the market

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<sup>2</sup> It can be shown that there is no incentive for a logical generator trader to offer capacity that is covered by hedge contracts, at anything other than SRMC. This ensures dispatch for the contracted capacity whenever pool prices are more than SRMC, which maximises the generator's position for the contracted portion of capacity.

through a strengthened desire among competing retailers to seek lower wholesale prices. Healthy competition among retailers which are separate from the distributor is also more likely to deliver higher quality of service to customers. Having a reasonable number, certainly not less than three, of competing retailers of a reasonable size also allows a deepening of the financial market, so essential for retailers and generator traders to manage market risk exposure.

### **3.3.2 Transfer of customer to private retailers**

The Scheme will see the contract (or negotiated) customers transferred from state-owned retailers to the private retail managers. These contract customers are already free to use any retailer they choose so it raises the important question as to why they have remained with the state-owned retailer. There are a number of possible reasons for this and these could be summarised as:

- lower prices offered by state-owned retailer because of special relationship with state-owned generators or perhaps a preparedness to offer non-economic prices to exclude competitors and cover the losses in other activities, including the regulated distribution component of the businesses;
- smaller customers switching from regulated to unregulated status remaining with the retailer they know; and/or
- uncertainty over service quality from new retailer.

The forced transfer of customers from state-owned retailers to a private retail managers could mean, therefore, that the private retail managers or any other competing retailers are unable to offer prices as low as was available through the state-owned retailers to the disadvantage of the electricity user when existing contracts with the state-owned retailers expire.

Furthermore, should the quality of service deteriorate under private retail managers, electricity users are likely to be worse off even though the state-owned retailers still have ultimate responsibility for the existing retail contracts.

The electricity user could be adversely affected if the successful private entity was to pay a high price for the retail manager contract and was looking to recover the payments from customers. This situation could be a very serious outcome for electricity users if all successful private retail managers paid high prices for the retail manager contracts.

### **3.3.3 Term of retail manager contracts**

It is difficult to envisage how the government will be able to re-auction the retail manager contracts. In effect, the retail manager contracts gradually expire as the existing electricity customers contracts with the state-owned

retailers expire. The only customers that could be pulled back for re-auction after five years would be those customers whose contracts with the state-owner retailers have not expired. Given that the vast bulk of retail contracts are for terms of less than three years, there are likely to be relatively few unexpired contracts after five years. In a similar way, most wholesale price - hedge contracts transferred from the state-owned retailers will have expired and so there would be very little of these to auction at the next round.

The transfer of these customers should be permanent, with the state-owned retailers servicing only franchise customers. Holding an auction each five years would remove the incentive for the retail trader to build the business. What happens, for example, if the trader loses customers? A five year term would also inhibit effective, lowest cost energy contracting strategy to the benefit of customers.

### **3.3.4 Importance of bilateral contracts**

A substantial proportion of wholesale energy purchases by retailers to service the contracted customers are through large out-of-market bilateral contracts directly between the retailers and generators. These contracts, particularly those between state-owned generators and state-owned retailers normally carry prices, which are below that of over-the-counter (OTC) contracts and electricity futures. They allow the retailers to offer lower retail prices to customers.

With the sale of the generator trader contracts, particularly if these are paired with retail manager contracts, the lower prices currently available through bilateral contracts are likely to either not be available to the retail managers or only available to those retail managers linked with a generator trader. This has potential to increase electricity prices and/or allow selected private retail managers to gain market advantage and increase market share, which is not in the long-term interests of electricity users.

### **3.3.5 Effects of forced transfer**

The electricity users will be forced, under the Scheme, to accept retail services from a retailer not of their choosing. While the state-owned retailers will continue to have legal responsibility for the existing retail contracts until their expiry, the billing and customer services will be undertaken by the private retail managers. The needs of electricity users should be protected so that, if a private retail manager fails to provide satisfactory service, then the customer has proper recourse to take the matter up with the state-owned retailer and if necessary be transferred to another private retailer of the customer's choosing. This protection is in addition to the normal protection available to electricity

users through the retailer code of conduct, in recognition of the forced transfer involved in the retail manager contracts.

### 3.3.6 Customer protection

The Further Discussion Paper suggests that there will be an appropriate code of practice applied to the retail trader through the retail licensing process. Given the competition in the retail sector, there is no justification to impose additional requirements on private retail managers than would normally apply to an independent private retailer. To do so could unnecessarily add to the costs of the private retail managers to the disadvantage of electricity users.

### 3.3.7 Greenhouse issues

The Further Discussion Paper suggests that the arrangements entered into by state-owned retailers to meet their greenhouse gas obligations for contract customers, could be transferred to the private retail managers but does not specify how this will be done. There is a wide variety of approaches to this issue and each has different cost characteristics.

Given that the state-owned retailers will still have greenhouse gas responsibility for customers on regulated tariffs, there is the obvious temptation to retain only the most cost effective greenhouse abatement schemes and transfer the higher risk, more expensive schemes to the private retail managers. Not only would such an approach place the private retail managers at a financial disadvantage with other private retailers, but it also has potential to result in increased electricity prices.

### 3.3.8 Demand management (DM)

The Further Discussion Paper states that the retail incentives for DM are preserved under the Scheme. This conclusion is based on two observations that:

- retailers have an incentive to obtain rights to reduce customer demand in order to enhance their hedging position; and
- demand reduction is a one of the least cost ways of meeting greenhouse benchmark targets under the NSW benchmarking scheme

It is generally agreed that the household sector, through increased penetration and use of air-conditioning, has been the main contributor to the system peak load growth and increased weather sensitivity in recent years. As such this sector would seem to offer the greatest DM opportunities. But, by allowing the vast majority of household customers to remain on regulated tariffs under ETEF and serviced by the state-owned retailers, the Scheme unfortunately does nothing to foster serious DM in this sector.

It is accepted that DM can benefit a retailer by reducing the need for hedge contract cover and provide some protection against price spikes. However, while DM may appear to be attractive to retailers from these perspectives, it also involves reducing sales, which clearly has a negative impact on retailers' revenues and profits.

The network service providers have more to gain from DM through reduced capital requirements but, until the recent IPART decision on distribution pricing, there were no incentives for these businesses to implement such schemes. Also, without access to customers in the same way as retailers, the network service providers will struggle to achieve significant advances with regard to DM. By splitting the retail and distribution services, the Scheme does have some potential to reduce the ability of distributors to implement DM schemes.

DM is largely neutral from the existing generators' perspective. DM may reduce the overall level of available hedge contract cover and by freeing-up generating capacity, provide opportunity for the generator traders to game the market. However, by reducing demand, DM limits the ability of the generators to increase pool prices. Most importantly from a generation perspective, DM, by reducing peak load, defers the need for additional capacity thereby providing cost savings to consumers.

Because the DM incentives for retailers, distributors and generators are limited and are not promoted under the Scheme, it is critical that the proposed NSW SOO will pay careful attention to the opportunities for DM and provide adequate information for market participants to make rational choices. This can be achieved by providing estimates of DM opportunities and ensuring that expected take-up of these is correctly reflected in the load forecasts.

The Scheme should recognize the importance of DM as a least cost approach to reducing price levels and volatility. This could at least partially be achieved by including in the tender documents for the generator trader and retail manager contracts, a request for bidders to outline the DM strategies that they intend to adopt. These responses would then be given an appropriate weighting in the bid evaluation process.

In addition, the Government should provide incentives for the state-owned retailers to introduce DM measures to the regulated tariff customers. This could, for example, be in the form of passing on part of the ETEF build-up to retailers for achieving targeted levels of DM to cover the metering and other costs as well as any compensation for lost margins arising from reduced sales. Successful DM should see a reduction in average pool prices which will be positive for the ETEF balance thereby providing the capacity for the fund to meet this extra obligation.

For the full benefits of DM to be realised it is also important that IPART and ACCC (or the Australian Energy Regulator in future), in settling the capital and operating budgets of the monopoly network service providers, ensure that the load reductions due to DM are fully reflected in the underlying load forecast.

## 4 Market modeling of the Scheme

### 4.1 Introduction

The possible market impacts of the Scheme have been analysed using ACIL Tasman's electricity market model – *PowerMark*. The model uses an hourly settlement period and produces hourly pool prices, station dispatch and interconnector flows. The model uses a linear program (LP) to settle the market overlaid with an optimisation module which implements a game theory approach to portfolio strategy. To this end, the model uses an iterative process to optimise the offer curves of the regional generation portfolios.

The model does not attempt to cover the retail end of the market although hedge contract cover is an important input to the development of the generator offer curves and the retail sector is an important consideration in this regard.

The main inputs to the model are:

- demand forecast;
- generation plant type and capacity, including installations and retirements;
- existing and new interconnector capacities and timing, and dynamic losses;
- marginal loss factors;
- planned and unplanned plant outages;
- generator contract cover;
- short run marginal cost (SRMC) of generation;

An outline of the model is at Attachment A.

The modeling covers the five years 2004/05 to 2009/10. The approach was to begin with a model run termed 'business as usual' (BAU) and then develop a number of scenarios in order to assess the likely market impacts of the Scheme.

The modeling involved using the BAU scenario as a reference case and developing a number of other scenarios where key assumptions have been adjusted to simulate the possible approaches available to private generator traders in NSW. The scenarios investigate a number of NEM offer strategies which would be available to private generator traders as well as the likely effects of generation portfolio options available to the NSW Government.

## 4.2 The scenarios

The scenarios presented are:

- Business as usual (BAU)
- Zero marginal cost
- Lower contract cover
- Five portfolios
- Five portfolios with lower contract cover

All scenarios are based on a set of realistic load, plant and other assumptions developed by ACIL Tasman to represent a likely market future based on publicly available load forecasts and proposed plant changes.

The scenarios, with one or two key assumption changes, are compared with the BAU to measure the impact on the regional prices, station dispatch and interconnector flows. These scenarios test various offer strategies available to the private generator traders in NSW and the portfolio options available to the NSW Government.

The scenarios assumptions and results are presented in the following sections.

### 4.2.1 Business as usual scenario (BAU)

The BAU scenario assumes the Scheme is not implemented and the three state-owned generator portfolios in NSW continue to offer capacity into the NEM. It is used as a reference case to quantify the changes which occur under a number of possible scenarios resulting from introduction of the Scheme. The assumptions underlying this market scenario are discussed in Section 4.3.

### 4.2.2 Zero marginal cost scenario

This scenario assumes a zero SRMC is used by private traders in offering the NSW coal fired portfolios into the NEM. This is based on the assumption that the periodic payments for coal are not linked to usage and are regarded by the private generator traders as a sunk cost, thereby resulting in a zero SMRC.

### 4.2.3 Lower contract cover scenario

A key strategy for private generator traders may be to reduce contract levels to lift pool prices. Under this scenario it is assumed that one of the largest private generator traders, MacGen, holds lower levels of contract cover to allow it greater discretionary capacity to game the market and possibly lift pool prices.

There is a strong link between the level of contract cover held by generation portfolios and pool prices. In general, lower contract cover means higher pool

prices because there is larger quantity of discretionary capacity available to the trader with which to game the market. Whilst the portfolio only receives this benefit of higher pool prices on the unhedged portion of capacity, in the longer-term, higher pool prices also influence the prices at which retailers are willing to hedge market exposures.

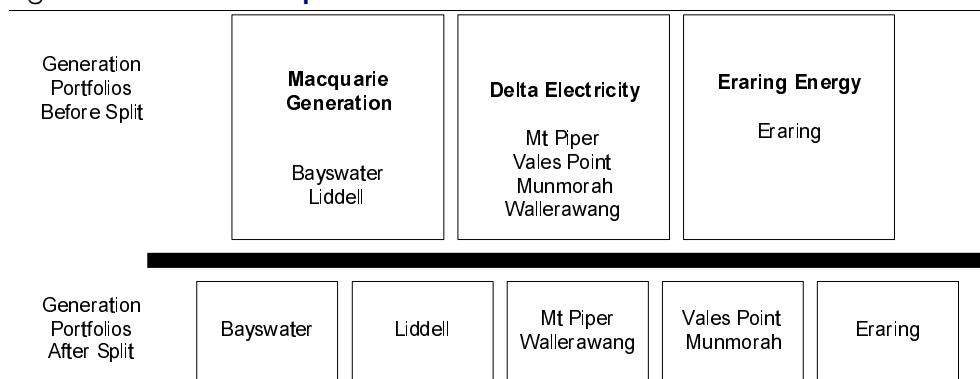
For this scenario the contract cover on the large MacGen portfolio has been reduced by five percentage points and the results compared to the BAU.

A case where the contract cover on all three portfolios, while probably unrealistic, was run for comparison purposes.

#### 4.2.4 Five portfolio scenario

The existing three generation portfolios in NSW are the largest in the NEM and are in a position to exert undue market power. The Scheme leaves open the possibility of auctioning smaller generation parcels to the private sector and this scenario examines the effects on the pool prices and station dispatch of having five generation portfolios in NSW. This involves splitting MacGen and Delta in two to have the portfolio structure as shown in Figure 10 :

Figure 3 Revised NSW portfolio structure



Offering smaller generation portfolios will dilute the market power and reduce the frequency and magnitude of market gaming activities in NSW. Lower pool prices are likely to result and this will tend to reduce the value of the trader contracts and reduce future payments to the NSW Government under the scheme. However, by reducing prices through dissipating generator market power, this scenario is attractive to electricity users.

For comparison, a case of seven, single station, portfolios was also run.

#### 4.2.5 Five portfolios with lower contract cover scenario

This scenario combines the five generation portfolios and reduced contract cover on the Bayswater, the largest of the five portfolios. It has been included

to examine the extent to which reducing the size of the portfolios provides a safeguard against private generator traders gaming the market by running lower hedge contract positions.

It is compared with the BAU and the BUU with MacGen's contracts cover reduced by five percentage points. It is also compared with the lower contract cover on Bayswater in the seven portfolio case.

### 4.3 Key modelling assumptions

This section provides a brief overview of the assumptions and model settings used in the BAU scenario. The assumption descriptions are split into six headings:

- load forecast;
- plant commencements and retirements;
- interconnector capacity;
- contract cover; and
- other assumptions.

#### 4.3.1 Load forecast

Growth in annual energy and peak load are important inputs to the BAU scenario. The official forecast of regional summer and winter peak demands and annual energy published by NEMMCO in its 2004 Statement of Opportunities (SOO) has been used as a base for the forecast.

The energy and load projections adopted from the SOO are the “medium” energy and “50% probability of exceedence” peaks.

The NEMMCO forecast includes an allowance for future large industrial loads only when these are confirmed and, as such, does not include the proposed Aldoga aluminum smelter, in Queensland. However the Aldoga smelter has been included in the BAU scenario as a 900MW load ramping up over three years from July 2007 to June 2010;

The inclusion of the Aldoga load drives the annual peak load requirements for Queensland above those of Victoria in 2006. All other things equal, the inclusion of this load will decrease the propensity of electricity generated in Queensland to be exported to NSW and Victoria.

Table 2 **Forecast annual energy requirements (GWh)**

	2004/05	2005/06	2006/07	2007/08	2008/9
<b>NSW</b>	75,720	77,460	79,150	80,510	82,250
<b>Queensland</b>	49,514	51,444	52,999	55,993	60,597
<b>SA</b>	12,754	12,704	12,934	13,255	13,476
<b>Tasmania</b>	10,587	10,690	10,793	10,958	11,201
<b>Victoria</b>	50,402	51,326	52,256	53,065	54,129

Data source: ACIL Tasman with NEMMCO

Details of the energy and demand forecasts are provided in Table 2 and Table 1 respectively. It should be noted that the projected annual energy and peak loads shown in Table 2 and Table 1 summarise the demand for electricity in each region, not the expected dispatch of generators within each region.

Table 3 and Table 4 summarise the percentage annual growth in energy and

Table 1 **Projected quarterly peak demands (MW)**

	NSW	Queensland	SA	Tasmania	Victoria
Jul - Sep 2004	12,830	7,305	2,324	1,716	7,864
Oct - Dec 2004	12,276	7,807	2,371	1,473	7,928
Jan - Mar 2005	12,660	8,187	3,026	1,415	8,997
Apr - Jun 2005	12,396	7,092	2,240	1,702	7,531
Jul - Sep 2005	13,120	7,640	2,369	1,731	8,027
Oct - Dec 2005	12,674	8,177	2,416	1,487	8,142
Jan - Mar 2006	13,080	8,587	3,111	1,404	9,274
Apr - Jun 2006	12,678	7,414	2,281	1,717	7,687
Jul - Sep 2006	13,300	7,986	2,408	1,745	8,182
Oct - Dec 2006	13,054	8,426	2,479	1,501	8,336
Jan - Mar 2007	13,480	8,847	3,199	1,417	9,509
Apr - Jun 2007	12,862	7,739	2,319	1,731	7,836
Jul - Sep 2007	13,500	8,200	2,460	1,772	8,327
Oct - Dec 2007	13,331	8,827	2,551	1,524	8,514
Jan - Mar 2008	13,770	9,290	3,296	1,464	9,725
Apr - Jun 2008	13,052	8,225	2,368	1,757	7,966
Jul - Sep 2008	13,720	8,740	2,500	1,813	8,504
Oct - Dec 2008	13,686	9,412	2,611	1,558	8,726
Jan - Mar 2009	14,140	9,886	3,380	1,471	9,981
Apr - Jun 2009	13,276	8,769	2,408	1,798	8,140
Jul - Sep 2009	13,980	9,311	2,552	1,854	8,695
Oct - Dec 2009	14,078	9,948	2,677	1,595	8,960
Jan - Mar 2010	14,550	10,431	3,472	1,506	10,262
Apr - Jun 2010	13,531	9,328	2,457	1,839	8,322

Data source: ACIL Tasman with NEMMCO

peak load. The higher percentage growth in most state's peak load compared with the growth in energy is principally due to an assumption of continued air-conditioning penetration in the domestic sector. The energy growth in Queensland in the later three years of the load forecast is higher than peak demand because of the influence of the very high load factor Aldoga smelter.

It is worth noting that expected renewable energy projects to meet the MRET targets are not included in the load forecast. Most of the renewable energy generation qualifying for the MRET is considered either load or load reduction

appliances, such as solar water heating. Embedded generation has the effect of reducing the load being met through the NEM. Even in the case of wind turbines generating into the NEM, they are often used as energy savers when linked to existing generators (such as the Tasmanian hydro system).

This deduction partly explains the comparatively lower annual growth in Victoria's energy consumption in the earlier part of the projection – due to the netting out of expected wind power generation. The expected growth in the embedded non-scheduled generation offsets (reduces) the energy and peak loads from the pool. The very high forecast growth in 2004/05 in SA is because peak demand of 2003/04 was affected by the mild summer and was well below a normal summer peak demand assuming median weather conditions.

**Table 3 Annual percentage growth in energy consumption**

	2004/05	2005/06	2006/07	2007/08	2008/9
<b>NSW</b>	2.8%	2.3%	2.2%	1.7%	2.2%
<b>Queensland</b>	2.6%	3.9%	3.0%	5.6%	8.2%
<b>SA</b>	-0.9%	-0.4%	1.8%	2.5%	1.7%
<b>Tasmania</b>		1.0%	1.0%	1.5%	2.2%
<b>Victoria</b>	2.3%	1.8%	1.8%	1.5%	2.0%

Data source: ACIL Tasman with NEMMCO

**Table 4 Annual percentage growth in peak demand**

	2005	2006	2007	2008	2009
<b>NSW</b>	5.4%	3.3%	3.1%	2.2%	2.7%
<b>Queensland</b>	3.2%	4.9%	3.0%	5.0%	6.4%
<b>SA</b>	16.7%	2.8%	2.8%	3.0%	2.5%
<b>Tasmania</b>		0.9%	0.8%	1.5%	2.3%
<b>Victoria</b>	5.5%	3.1%	2.5%	2.3%	2.6%

Data source: ACIL Tasman with NEMMCO

### 4.3.2 The standard year of hourly loads

*PowerMark* simulates the NEM on an hourly basis (with hourly, not half hourly, settlement periods).

The *PowerMark* database uses a simulated hourly load profile for each region based on actual half-hour generated load observations for the four years 1998-99 to 2001-02 and temperature and humidity data for 1970-71 to 2001-02. A synthetic 'standard year' is created by randomly choosing a temperature and humidity profile for each day of the standard year from the 1970-71 and 2001-02 data base of daily temperature and humidity profiles.

The hourly load profile for each day in the 'standard year' is selected from the four load data years with the closest matching temperature conditions and same day type (day of week, month of year, working day, -non-working day). This is achieved by finding the closest least squares match between the

temperature profile for that day in the standard year and the temperature profile for a day in one of the four load data years.

The standard year of simulated hourly loads is scaled for each year of the projection based on the projected winter and summer peak demands and annual energy. Technically, a linear transformation method has been used to ensure all hourly data conform to both the annual energy and the winter and summer peak loads.

### 4.3.3 Generation plant changes

Future generation capacity to supply electricity during the projection period is dependent on:

- capacity and type of existing generation;
- capacity, type and timing of plant retirements;
- capacity, type and timing of new plant (new entrants); and
- frequency and length of maintenance programmes as well as assumed forced outage rates.

When taken together with the electricity consumption forecast, the assumptions regarding plant additions and retirements will determine the supply-demand balance and are critical to the modelling results.

Table 5 outlines the withdrawals and additions of plant assumed in the BAU.

In NSW the increase in capacity of MacGen and Delta units has a significant effect on available capacity. Two of MacGen's Liddell units underwent refurbishment (resulting in a higher capacity and improved efficiency) in 2003 – these two units are operating on a full-time basis from the beginning of the projection period. The third Liddell unit was returned to full time service in June 2004 after previous use as a backup and the fourth unit is assumed to remain as a backup until December 2005. It is assumed that the first of the Munmorah units changes from a back-up roll to full-time service in June 2006 and the second unit returns to full-time service in January 2007. The four Bayswater units are assumed to undergo an upgrade, adding 20MW per unit (to give a nameplate capacity of 680MW) between October 2003 and June 2004<sup>3</sup>. A new coal fired plant is added in NSW in July 2008 and a new CCGT in December of that year.

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<sup>3</sup> The Bayswater units were originally reported to have an upgrade of 40MW (taking the capacity to 700MW per unit) but ACIL Tasman analysis of the offer data from Bayswater over the past 12 months suggests clearly that the maximum capacity offered to the NEM is 680MW per unit.

CS Energy's Callide A station has not operated since December 2001 and we have assumed it does not return to service. Swanbank B is assumed to undergo refurbishment in the 2004 calendar year. Enertrade is assumed to have the equivalent of one Gladstone unit off-line from 2004 to 2007. Further, on the basis of our assumption that CSM gas will be available in Queensland from January 2005, we assume the refiring of Yabulu as a 220MW CCGT. Kogan Creek's commissioning date is set to be November 2007. Additional new entrant CCGTs are assumed in Queensland post 2008. However, not all new entrants are assumed to be gas-fired.

In SA, Thomas Playford is assumed to undergo an upgrade in 2004 and 2005, the net result being an improvement in auxiliary usage and thermal efficiency – this is based on information contained in the latest NEMMCO SOO and ACIL Tasman sources.

In Victoria, Loy Yang A is assumed to undergo an upgrade process between 2003 and 2007 – adding between 10MW and 40MW in capacity per unit and Hazelwood is assumed to gain 20MW in capacity for each of seven of its units in 2004/05. Modelling suggests that projected Victorian pool price does not support further new entrants in Victoria in the next five years including Origin Energy's proposed base load plant in Western Victoria

Table 5 **Additions to and withdrawals from generation capacity, by region**

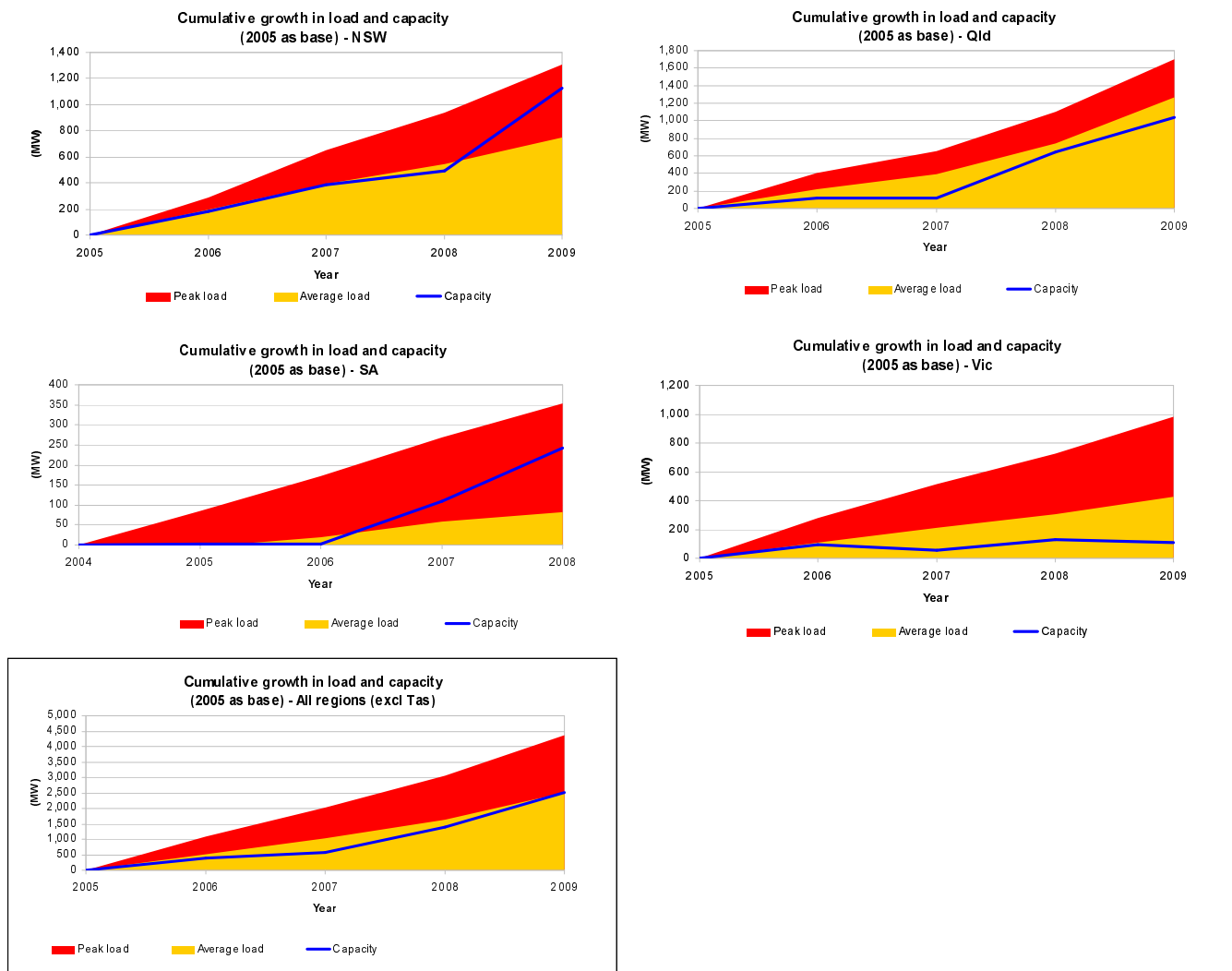
Portfolio	Generator	Type	Nameplate capacity (MW)	Date-on
<b>Victoria</b>				
Loy Yang Power	Loy Yang A	Brown coal	+10-40 per unit	Jul 2003 – Jun 2007
Hazelwood Power	Hazelwood Power Station	Brown coal	+20MW per 7 units	Jul 2004 – Jun 2005
<b>New South Wales</b>				
Macquarie Generation	Liddell U1 – U2	Black coal	+15 per unit	2003/04
Macquarie Generation	Liddell U3	Black coal	515	Return to full-service in Jun 2004
Macquarie Generation	Liddell U4	Black coal	515	Return to full-service in Dec 2005
Macquarie Generation	Bayswater U1 U4	Black coal	+40 per unit	Oct 2003 - Jun 2004
Delta	Munmorah U3	Black coal	300	Jan 2007 (changing from backup to full-service)
Delta	Munmorah U4	Black coal	300	Jun 2004 – backup role; Jun 2006 – full-time service
New entrant	NE Peaker	GT/Gas	150	Jan 2007
New entrant	NE Coal	Black coal	450	Jul 2008
New entrant	NE CCGT	CCGT/Gas	380	Dec 2008
<b>South Australia</b>				
NRG Flinders	Thomas Playford	Brown coal	4x60MW	Jan 2004 – Jul 2005 (refurbishment)
New Entrant	NE CCGT	CCGT/Gas	150	Feb 2008
<b>Queensland</b>				
Enertrade	Yabulu	CCGT/Gas	226	Jan 2005 (conversion)
CS Energy	Kogan Ck	Black coal	750	Nov 2007
Enertrade	Mt Stuart	CCGT/Gas	454	Dec 2009 (conversion)

Data source: ACIL Tasman

### 4.3.4 Supply demand balance

Figure 4 provides a stylised summary on an annual basis of the growth in load and generation capacity for each region in the BAU scenario of peaking capacity to Victoria (and therefore offsetting the reduction in reserve margin).

Figure 4 Cumulative growth in load and capacity by region –BAU base case



Data source: ACIL Tasman

### 4.3.5 Interconnector capacity

Interconnectors can either be a source of lower priced electricity coming into a region, or a means to export surplus capacity. The interconnector capacities used in the modelling are largely taken from NEMMCO's Annual National Transmission Statement (ANTS) but have been adjusted where necessary to incorporate interconnector capacity which would seem to be justified from a market perspective. The main difference is the inclusion of a Snowy to SA

interconnector (SNI) which has been included in the modelling as increased interconnector capacity into SA, as it avoids the need for an additional 250MW of peaking capacity in SA. It has been chosen over an increase in the Heywood interconnector as muted in the 2004 ANTS because it provides a more direct link between the SA market and available capacity. A summary of the interconnectors and interconnector expansion assumed in the BAU scenario is shown in Table 6.

Table 6 **Assumed total interconnection capacity (MW)**

From	To	Jan-04	Jan-05	Jan-06
Snowy	Vic	1900	1900	1900
Vic	Snowy	1100	1100	1100
Snowy	NSW	3000	3000	3000
NSW	Snowy	1150	1150	1150
Vic	SA	460	460	460
SA	Vic	300	300	300
Vic – ML	SA – ML	220	220	220
SA – ML	VIC – ML	120	120	120
Vic	Tas			300
				480 (600 for upto 3 consecutive hours)
Tas	Vic			
NSW	SA			250
SA	NSW			250
NSW	Qld	700	700	700
Qld	NSW	950	950	950
NSW – DL	Qld – DL	180	180	180
Qld – DL	NSW – DL	180	180	180

Data source: ACIL Tasman

#### 4.3.6 Contract cover

Contract cover measures the extent to which generators have their pool price exposure covered by financial swap contracts (two-way hedges)<sup>4</sup>. The extent of contract cover across the whole market, whether expressed as a proportion of available capacity or of market demand, can only be guessed at — or speculated about from anecdotal evidence. Individual portfolios, of course, are keenly aware of the position in respect of their own business — but this is not information they divulge.

In modelling pool markets, the level of contract cover is a driving factor in price and dispatch outcomes. Based solely on short-run analysis, a generator is usually inclined to offer most contracted capacity at marginal cost (save for below marginal cost bids in respect of must run minimum generation (MinGen) and ramp-up needs<sup>5</sup>), and will bid to maximise net revenues from the remaining uncontracted capacity.

<sup>4</sup> One-way hedges (caps) impact on generator offering behaviour only to the extent that they relate to plant capacity that would normally be off-line.

<sup>5</sup> ‘MinGen’ (for minimum generation) is the estimated minimum level at which a plant can be technically and economically operated (for flame control and damage limitation). Generators usually offer this level of capacity at near zero or substantially

Proxy values of contract cover have been established for recent periods by ‘reverse engineering’ the contract cover and contract target assumptions such that they replicate actual power station dispatch and pool prices when actual demand data and estimated actual outage data are substituted for projected demand and outages. The estimates derived in that way are plausible numbers in the opinion of market participants familiar with them.

**The level of contract cover in the market is expected to stabilise, on a long term basis, at about 85% of all demand.** Based on our modelling, this seems to allow new entrants a reasonable level of contract cover, as well as maintaining the contract levels of existing base load plant. Furthermore, analysis of the generator offer curves and simulation of the market over the past three years suggests that stable contract cover of 85 % is a reasonable assumption.

The assumption of relatively stable contract cover is also based on the fact that in a rising market retailers will be seeking to increase contract cover while generators will be inclined to reduce contract cover. Given that reduced contract cover is a greater risk for the retailer than the generator, the rising market is likely to be characterised by increased contract premiums rather than a reduced contract cover and vice versa in a falling market.

It is important to note that the levels of contract cover in the market assumed in the base case in this report are expressed in terms of load and not in terms of capacity. The supply to demand ratio, on an annual basis, throughout the projection varies from 160% to 180%. Therefore, a system load contract cover level of 85% would equate to about 50% of generator capacity being covered by contracts. This is not to say that all stations will have 50% contract cover – ACIL Tasman assigns a level of contract cover to each station based on an analysis of the relative competitiveness of the station, historical contract levels and market intelligence.

#### 4.3.7 Other assumptions

The period modelled by PowerMark is July 2004 to June 2009. The main purpose of the modelling is to quantify the possible effects of the Scheme under a variety of market conditions expected over the next few years as the supply demand balance tightened and prices begin to recover. The period selected includes major additions to plant capacity in NSW in mid to late 2008.

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negative prices in order to avoid being offloaded by the central dispatcher. It is rare — but does occur — for the pool price to settle at a negative “offload” price. Generators also tend to offer capacity at below marginal cost for periods when they are intent on ‘ramping-up’ in order to have the ability to offer greater amounts of capacity in a subsequent period, when pool prices are expected to be higher.

All prices projected in this report are ‘real prices’: measured in constant Australian dollars **at 1 January 2004 prices**.

Unless specifically stated to the contrary, electricity quantities projected in this report are **“generated” quantities**. Market demand and supply are balanced at the regional reference nodes (i.e. after allowing for intra-regional and inter-regional losses in transmission).

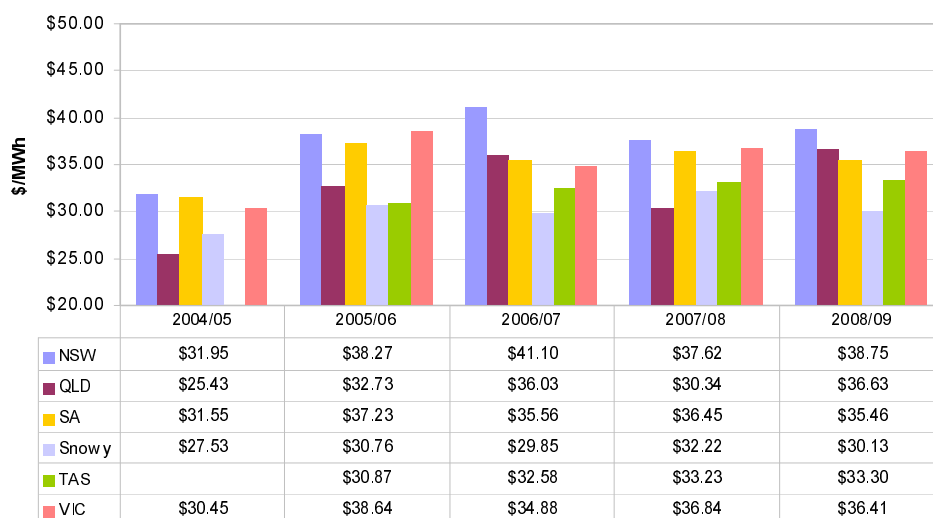
## 4.4 Modeling results

### 4.4.1 BAU scenario

#### Regional pool prices

The pool prices from the modeling for BAU scenario is shown in Figure 5.

Figure 5 **Average pool prices in the BAU scenario**



Data source: from PowerMark modelling

The main features of the regional pool prices are:

- The Queensland price during the first two years of the projection is lower than the other states with the introduction of cheap coal-fired capacity between 2001 and 2003 resulting in the price of only \$25.43/MWh in 2004/05. Queensland exports strongly to NSW during this time and the interconnector constrains on a regular basis, thus contributing to the overall price separation.
- Prices in the southern states increase in 2005/06 with the assumptions that contract volumes return to lower more normal levels and with the only capacity addition being in the form of upgrades.

- Interconnection with Tasmania impacts on the NEM in 2006/07 providing Victoria with increased access to cheaper energy during peak periods. As a result, between 2005/06 and 2006/07, prices in the southern states are constrained with Basslink. Conversely, the Queensland price grows strongly in 2006/07 with the ramping up of Aldoga – the Queensland price converges towards the prices of the southern states but decreases temporarily in 2007/08 with the assumed commissioning of Kogan Creek at the end of 2007, which also impacts on the NSW price in that year.
- Prices in the southern regions hover around the \$35.00/MWh throughout much of the projection period as expansions, recommissioning and new entrants tend to balance load growth. The price is partly controlled by the gradual return to full-time service of the Liddell and Munmorah units and the assumed commissioning of SNI and Basslink.
- The price in NSW exceeds the prices in the other regions partly because it is less affected by Basslink and no new plant is added until the latter half of 2008

### Dispatch and capacity factors

Dispatch and capacity factors for each of the three NSW state-owned portfolio generators, and contributions from other generators and net imports to the NSW market are shown in Table 7. Over the next five years, the three state-owned portfolios supply between 85% and 87% of to the NSW electricity needs, with between 6% and 12% coming from exports and the rest from other NSW generators. The sizeable increase in the contribution from other generators in 2008 is associated with the commencement of a new 450MW coal fired plant in July 2008 and a new 380MW CCGT in December 2008 (see Table 5).

Table 7 **Dispatch, capacity factors and shares in NSW in the BAU scenario**

Energy source	2004/05	2005/06	2006/07	2007/08	2008/09
Energy supply to NSW (GWh)					
Macquarie Generation	29,057	29,603	31,363	31,488	31,140
Delta Electricity	21,827	22,052	23,912	24,754	25,073
Eraring Energy	13,721	14,498	14,112	14,742	14,343
Generation from other NSW stations	2,394	2,518	2,538	2,556	6,077
Net Imported energy	8,941	9,036	7,458	7,206	4,744
Share of supply					
Macquarie Generation	38%	38%	40%	39%	38%
Delta Electricity	29%	28%	30%	31%	31%
Eraring Energy	18%	19%	18%	18%	18%
Generation from other NSW stations	3%	3%	3%	3%	7%
Net Imported energy	12%	12%	9%	9%	6%
Capacity factors					
Macquarie Generation	74%	73%	75%	75%	74%
Delta Electricity	68%	68%	67%	66%	68%
Eraring Energy	59%	63%	61%	64%	62%

Data source: PowerMark modelling

### Interconnector flows

Interconnector flows to and from NSW are shown in Table 8. The net flows into NSW reduce over the five year projection from around 9,000GWh to around 4,750GWh in 2007/08. The main reasons are increased generation capacity in NSW and a tightening in the supply/demand balance in Queensland and Victoria meaning there is less capacity to export energy. The level of constraint on inward flows also reduces noticeably whereas the outward flow constraints increase.

The constraints on interconnectors from Queensland to NSW have caused a price separation between NSW and Queensland of between \$5.07 and 7.28/MWh in the initial four years of the projection and \$2.12/MWh in the final year when constraints fall because the new generation capacity in NSW significantly reduces net imports. This suggests that the interconnector capacity is inadequate for the current plant and load balance in Queensland and NSW although the constraints are eased considerably by the new generation capacity assumed in NSW in 2008/09.

Powerlink and Trangrid are currently evaluating whether an expansion of QNI is able to pass the new regulatory test which incorporates a market benefit test. However it remains to be seen whether this attempt will be successful. The NSW generators have most to lose from an expanded QNI and believed to be actively opposing such an expansion, which will reduce market power of the NSW generators, leading to reduced dispatch and lower prices in NSW.

On the other hand it is the NSW electricity users which will benefit most from and expanded QNI. In this regard, notwithstanding the inclusion of “competition benefits” in the regulatory test, the concern among electricity users that any enhancement of interconnectors is likely to remain problematic with still no real consideration given to end-user benefits.

Table 8 **Interconnector flows to and from NSW in the BAU scenario**

	2004/05	2005/06	2006/07	2007/08	2008/09
	Interconnector flows (GWh)				
Qld to NSW by QNI	5,233	4,646	4,449	4,569	3,654
NSW to Qld by QNI	73	89	161	120	281
Qld to NSW by Directlink	1,045	1,190	1,149	1,167	969
NSW to Qld by Directlink	7	15	29	22	55
Snowy to NSW	3,862	4,575	3,948	3,862	3,143
NSW to Snowy	1,119	1,270	1,898	2,249	2,687
Net imports	8,941	9,036	7,458	7,206	4,744
	Percentage of time constraining				
Qld to NSW by QNI	15.9%	11.7%	9.6%	10.9%	5.8%
NSW to Qld by QNI	0.1%	0.0%	0.2%	0.3%	0.7%
Qld to NSW by Directlink	40.7%	48.4%	46.2%	46.5%	32.4%
NSW to Qld by Directlink	0.0%	0.0%	0.1%	0.2%	0.5%
Snowy to NSW	0.1%	0.5%	0.7%	0.3%	0.4%
NSW to Snowy	0.6%	1.2%	3.1%	4.8%	6.2%

Data source: PowerMark modelling

### Gross pool revenue

The gross pool revenue earned by each NSW portfolio is shown in Table 9. The increase in NSW pool prices in the initial years and increased dispatch in the latter years of the five year projection results in real gross pool revenue increases for all three NSW generation portfolios.

It should be noted that these estimates of gross pool revenues should not be taken as generator revenue as this will depend upon a host of factors, including the level of hedge contract cover, hedge contract prices and pool prices. It is presented to provide an idea of whether movements in pool prices and station dispatch between the BAU scenario and other scenarios is positive or negative for the NSW portfolios.

Table 9 **Gross pool revenues in the BAU scenario (\$ million)**

	2004/05	2005/06	2006/07	2007/08	2008/09
Macquarie Generation	1,335	1,691	1,778	1,670	1,692
Delta Electricity	1,065	1,321	1,535	1,470	1,521
Earing Energy	827	968	1,103	978	1,048

Data source: PowerMark modelling

### 4.4.2 Zero marginal cost scenario

This scenario was run to test the application of an effective zero SRMC by private traders in offering the NSW coal fired portfolios into the NEM.

It has been identified as one possible approach of a private generator trader to the periodic charge for coal to cover the contractual obligation of the state-owned generation portfolios. This assumes that the periodic payments for coal

are regarded by the private generator traders as a sunk cost and, as such, have no impact on the cost of the next unit of generation.

Having an effective zero SRMC would make the NSW coal stations appear cheaper to the market and be dispatched at a higher priority over other stations in the NEM. Within the modeling framework, these stations will continue to offer min-gen quantities at negative prices and any contracted capacity above the min-gen level, at SRMC (in this case \$0/MWh). Available capacity above this contracted level will still be determined through the optimisation process, which will select the optimal strategy for each portfolio.

### Pool price impacts

Allowing the private generator traders to offer the three NSW portfolios at zero between their min-gen and their contracted capacity has resulted in a decline in prices across the NEM compared with the BAU scenario as shown in Figure 6. Pool prices decline less than \$2.00/MWh in all years, except 2008/09 when the decline is generally between \$2.00 and 3.00/MWh.

The low impact on pool prices is partly a result of the constant contract cover, which has meant that the size of the discretionary component of capacity has not changed. This allows the powerful NSW portfolios to game the market to minimise downward price movements. While a zero SRMC would allow the portfolios to be offered entirely at \$0/MWh, the detrimental impact on pool price of doing so makes this a non-optimal strategy as pool revenues would be seriously eroded.

Figure 6 **Regional pool price changes between BAU scenario and the zero marginal cost scenario**



Data source: PowerMark modelling

### Impacts on dispatch

The zero SRMC offering strategy by the NSW generation portfolios has a generally positive impact on dispatch and capacity factors for all but Delta as shown in Table 10. The negative impact on Delta's dispatch is because the change in offer price in moving to zero SMRC was less for the Delta portfolio than for the other two portfolios so the increase in competitiveness of the Delta portfolio was less than for the other two directly competing portfolios and also insufficient to displace imports sufficiently.

Table 10 **Change in dispatch, capacity factors and shares between the BAU scenario and the zero marginal cost scenario**

Energy source	2004/05	2005/06	2006/07	2007/08	2008/09
Change in energy supply to NSW (GWh)					
Macquarie Generation	1,900	1,683	1,284	1,295	2,213
Delta Electricity	-583	-647	-447	-357	688
Eraring Energy	1,836	1,739	1,532	1,640	2,149
Generation from other NSW stations	-132	-116	-117	-119	-577
Net imported energy	-2,911	-2,567	-2,151	-2,381	-4,408
Change in share of supply					
Macquarie Generation	2.4%	2.1%	1.6%	1.6%	2.7%
Delta Electricity	-0.8%	-0.9%	-0.6%	-0.5%	0.8%
Eraring Energy	2.4%	2.2%	1.9%	2.0%	2.6%
Generation from other NSW stations	-0.2%	-0.2%	-0.2%	-0.1%	-0.7%
Net imported energy	-3.8%	-3.3%	-2.7%	-3.0%	-5.4%
Change in capacity factors					
Macquarie Generation	4.8%	4.1%	3.1%	3.1%	5.3%
Delta Electricity	-1.8%	-2.0%	-1.2%	-1.0%	1.9%
Eraring Energy	7.9%	7.5%	6.6%	7.1%	9.3%

Data source: PowerMark modelling

### Impacts on gross pool revenue

The increases in dispatch of the NSW generation portfolios (apart from Eraring) is not sufficient to offset the price decline and, as a result, gross pool revenues declined in the zero marginal cost scenario as shown in Table 11.

It seems that the lower the SRMC used in the BAU, then the greater the decline in gross revenue. In aggregate, however, the gross pool revenue is roughly equal across the portfolios, with the zero SRMC scenario resulting in a revenue transfer from the previously lower cost portfolios (MacGen and Delta) to the higher cost Eraring Energy.

Table 11 **Change in gross pool revenue between the BAU scenario and the zero marginal cost scenario**

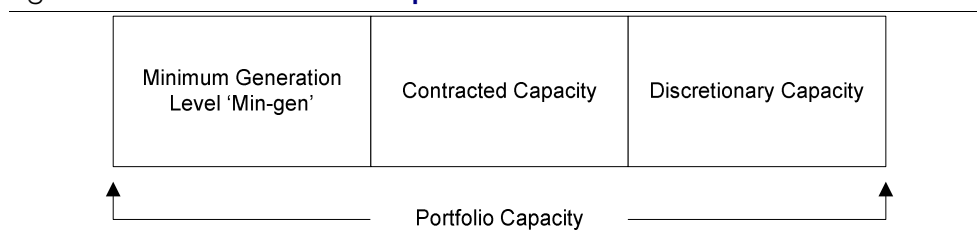
	2004/05	2005/06	2006/07	2007/08	2008/09
	Change in gross pool revenue (\$ million)				
Macquarie Generation	-125	-125	-122	-75	-193
Delta Electricity	-49	-31	-52	-30	-137
Eraring Energy	-96	-105	-114	-74	-160
	Percentage change in gross pool revenue				
Macquarie Generation	-9.4%	-7.4%	-6.8%	-4.5%	-11.4%
Delta Electricity	-4.6%	-2.3%	-3.4%	-2.0%	-9.0%
Eraring Energy	-11.6%	-10.8%	-10.3%	-7.6%	-15.2%

Data source: PowerMark modelling

#### 4.4.3 Lower contract cover scenario

Generator portfolios offer their capacity to the market based on their unique physical plant and financial hedge arrangements. Portfolios effectively have three different tranches of capacity which is able to be offered to the market as shown in Figure 7.

Figure 7 **Portfolio offer curve representation**



The min-gen level will vary from station to station (in some cases unit to unit) within the portfolio based upon technical ability to hold a unit on line. This tranche of capacity is typically offered at large negative prices in the NEM, which has a floor price of  $-\$1,000/\text{MWh}$  and reflects the high economic cost of taking the unit off-line. This capacity is assumed in the modeling to be fully hedged.

The contracted tranche is the amount of portfolio output beyond the min-gen level, which is hedged through bilateral contracts and tradable over-the-counter (OTC) contracts or futures. A portfolio will typically offer this component of contracted capacity beyond the min-gen level at SMRC to maximise the benefit of these hedges.

The third tranche is capacity, which is not covered by hedge contracts and hence is exposed to the prevailing pool price. The ETEF component of the NSW generator capacity is included in this tranche. A portfolio will decide the portion of this tranche to offer at low enough prices to be dispatched, with the remainder offered at higher prices in an attempt to influence the prevailing pool prices. By doing this, portfolios are making a price-quantity trade-off (low price, high dispatch or high price, low dispatch). This 'gaming' behavior

in the market is commonplace and on some occasions — typically periods of high demand coinciding with forced plant outages — economic withholding of capacity can cause prices to spike.

There is a strong link between the level of contract cover held by generation portfolios and pool prices. In general, lower contract cover means higher pool prices because there is larger quantity of discretionary capacity available to the trader. By extension, the bigger the portfolio, the greater the possible impact on prices. Whilst the portfolio only receives this benefit on the unhedged portion of capacity, in the longer-term, higher pool prices also influence the prices at which retailers are willing to hedge market exposures.

A key strategy for a private generator trader may be to reduce contract levels to lift pool prices. This has been tested by reducing contract cover on the NSW generators by five percentage points and observing the impact on prices, dispatch and gross pool revenue by the NSW portfolios. It must be stressed that, while we have reduced the constraint upon NSW portfolios to offer capacity at SRMC, the optimisation process still allows the portfolios to offer this capacity at SRMC if this represents the optimal strategy for the portfolio.

The level of contract cover and price is a function of the expected level and volatility of future pool prices. In recent years contract cover is estimated to have settled at around 85% of the market. Retailers, wanting to cover their forward price position, are the main drivers of contract cover and generally the higher the expected level and/or volatility of future prices then the higher the desired level of contract cover and the higher prices retailers are prepared to pay.

The modeling is projecting increasing average annual pool prices in the coming years and slightly increased price volatility. This suggests that retailers will be wishing to hold contract cover at least around its current proportion of the market. However, individual generating portfolios may see greater advantage in moving to a lower level of contract cover in order to game the market and achieve higher prices for the uncontracted portion than retailers are prepared to bid for contracts. This market strategy will be more attractive to larger portfolios such as MacGen which have a greater chance of influencing the pool price.

On this basis, larger generation portfolios may choose to accept a lower level of contract cover on the basis that by adopting an appropriate offer strategy they can achieve higher pool prices than the contract price being bid by retailers. Whilst we have no firm basis for suggesting a five percentage point reduction in contract cover is likely due to the Scheme, such a value is well within plausible bounds.

This scenario investigates the change to the BAU if the largest of the three portfolios, MacGen, were to reduce its contract cover by five percentage points. It is assumed here that only one of the three generation portfolios reduces contract cover, however, the effects are far more dramatic if contract cover were to be reduced for all three portfolios. A case where all three portfolios reduce contract cover has been run and used for comparison.

### Pool price impacts

A five percentage point reduction in contract cover on the MacGen portfolio causes a marked increase in pool prices compared with the BAU scenario, especially in NSW and Queensland, as shown in Figure 8. This is because the five percentage point reduction provides a significant increase in discretionary capacity available to the largest and most powerful NSW generating portfolio, MacGen, to game the market. The impact on price is largest when plant load balance is at its tightest, as in 2005/06. The impact of higher NSW pool prices is transmitted throughout the entire NEM — including Tasmania upon its joining the market.

Figure 8 **Regional pool price changes between the BAU and the lower contract cover (for MacGen) scenarios**



Data source: PowerMark modelling

If all three portfolios were to reduce contract cover by five percentage points then the change in the BAU pool prices is roughly twice as high as when only MacGen reduces contract cover, as shown in Figure 9. However this case where all portfolios reduce contract cover is considered most unlikely as retailers will be likely to bid contract prices upwards and induce generators to take up the contracts.

Figure 9 **Regional pool price changes between the BAU and a case where the contract cover is lower for all three portfolios**



Data source: PowerMark modelling

### Impacts on dispatch

The lower contract cover by MacGen has a negative impact on dispatch and capacity factors for MacGen and NSW overall, although has a small positive affect on most other NSW portfolios, compared with the BAU, as shown in Table 12. Effectively the strategy employed by the generator trader for MacGen is akin to shifting the NSW electricity supply curve to the left, resulting in higher prices and a lower level of dispatch. As a result, of the lower output, net imports into NSW have increase noticeably.

Table 12 **Change in dispatch, capacity factors and shares between the BAU and the lower contract cover (for MacGen) scenario**

Energy source	2004/05	2005/06	2006/07	2007/08	2008/09
Change in energy supply to NSW (GWh)					
Macquarie Generation	-879	-967	-1,056	-1,054	-1,016
Delta Electricity	14	-11	-32	13	2
Ering Energy	104	115	113	179	183
Generation from other NSW stations	14	20	20	24	23
Net Imported energy	767	869	980	860	813
Change in share of supply					
Macquarie Generation	-1.2%	-1.3%	-1.3%	-1.3%	-1.3%
Delta Electricity	0.0%	0.0%	0.0%	0.0%	0.0%
Ering Energy	0.1%	0.1%	0.1%	0.2%	0.2%
Generation from other NSW stations	0.0%	0.0%	0.0%	0.0%	0.0%
Net Imported energy	1.0%	1.1%	1.2%	1.1%	1.0%
Change in capacity factors					
Macquarie Generation	-2.2%	-2.4%	-2.5%	-2.5%	-2.4%
Delta Electricity	0.0%	0.0%	-0.1%	0.0%	0.0%
Ering Energy	0.5%	0.5%	0.5%	0.8%	0.8%

Data source: PowerMark modelling

### Impacts on gross pool revenues

The lower dispatch of the MacGen portfolio is more than offset by the strong pool price increase and, as a result, gross pool revenues in the lower contract cover (for MacGen) scenario are significantly higher than in the BAU as shown in Table 13. The increased gross pool revenues verify the successful nature of strategic behavior employed. However, due to their hedged positions, portfolios will only capture a relatively small portion of this increased revenue in the short-term. In the longer term it may result in lower contract cover and higher pool and contract prices.

Table 13 **Change in gross pool revenue between the BAU and the lower contract cover (for MacGen) scenarios**

	2004/05	2005/06	2006/07	2007/08	2008/09
Change in gross pool revenue (\$ million)					
Macquarie Generation	186	618	648	319	308
Delta Electricity	170	523	597	319	281
Ering Energy	122	389	425	213	220
Percentage change in gross pool revenue					
Macquarie Generation	13.9%	36.6%	36.5%	19.1%	18.2%
Delta Electricity	16.0%	39.6%	38.9%	21.7%	18.5%
Ering Energy	14.8%	40.1%	38.6%	21.8%	21.0%

Data source: PowerMark modelling

### 4.4.4 Five portfolio scenario

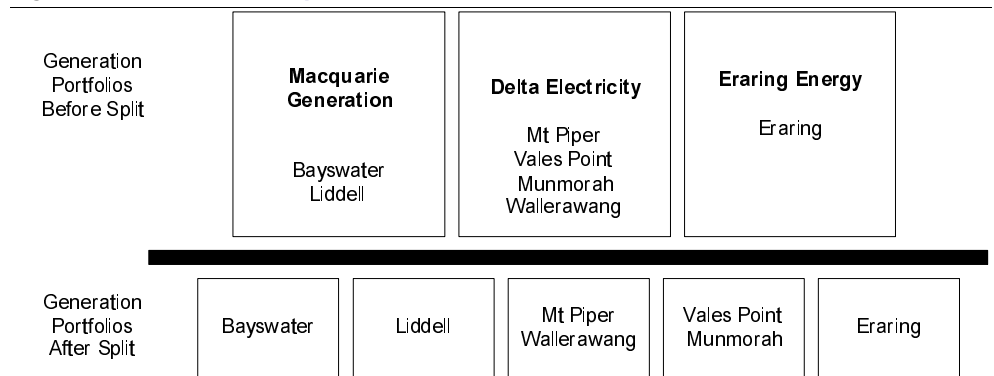
The existing three generation portfolios in NSW are the largest in the NEM and are in a position to exert undue market power as shown in the previous scenario. This could be even more so under a private generator trader. The Scheme leaves open the possibility of auctioning smaller generation parcels to

the private sector, although presumably for efficiency reasons the existing three portfolios are to be retained for operational purposes.

Offering smaller generation portfolios will dilute the market power and reduce the frequency and magnitude of market gaming activities in NSW. Lower pool prices are likely to result and this will tend to reduce the value of the trader contracts and reduce future payments to the NSW Government under the scheme. However, by dissipating market generator power, this scenario is more attractive to electricity users.

A variant of the BAU scenario was investigated with five rather than three generation portfolios as shown in Figure 10. A case with seven, single station, portfolios was also run for comparison.

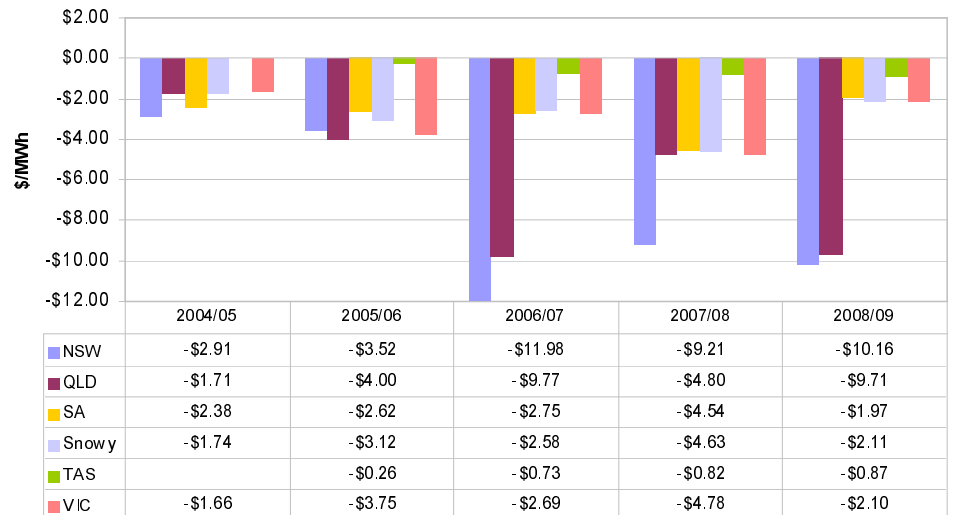
Figure 10 **Revised NSW portfolio structure**



**Pool price impacts**

Using five instead of three NSW generating portfolios causes a significant decrease in pool prices compared with the BAU scenario, especially in NSW and Queensland as shown in Figure 11. The five portfolios do not have the market power to maintain higher prices even in the absence of a tight supply-demand balance. The reduction in prices is magnified when plant load balance is at its tightest, as in 2006/07, and pool prices in the BAU are able to be driven upwards by the larger NSW portfolios.

Figure 11 **Regional pool price changes between the BAU and the five portfolio scenarios**

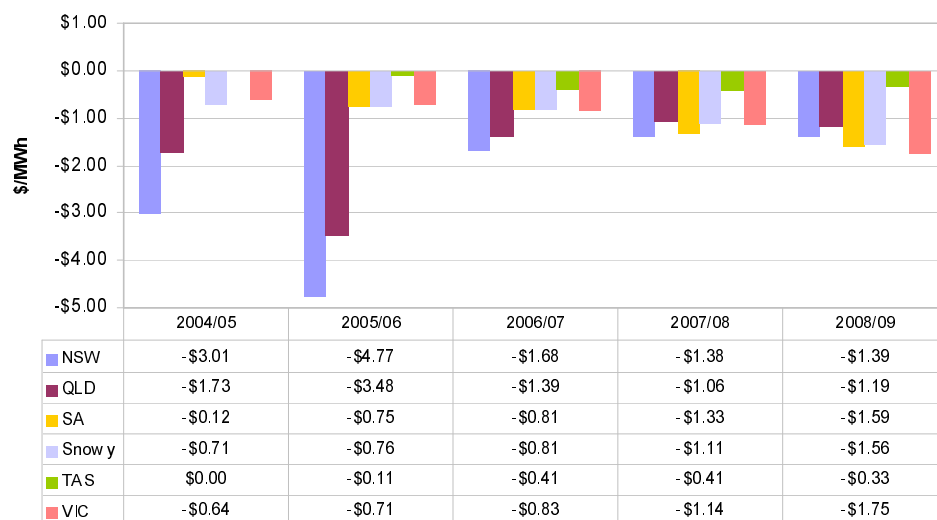


Data source: PowerMark modelling

Moving to seven, single station, portfolios showed a further lowering in prices is possible, as shown in Figure 12. However, this would involve four of the seven portfolios containing only two generating units which, by seriously eroding these single station portfolios ability to hold adequate contract cover, is likely to have serious adverse consequences for the depth of the financial market and the size of the hedge contract price premiums.

Furthermore, the model seven scenario run assumes no deterioration in contract cover which is probably unrealistic for some of the two generator portfolios. If contract cover was reduced to realistic levels in the seven portfolio case then the pool prices can be expected to be higher than in the five portfolio scenario.

Figure 12 **Regional pool price changes between the five and seven portfolio structures**



Data source: PowerMark modelling

### Impacts on dispatch

The larger number of smaller NSW generation portfolios (5 instead of 3) has a positive impact on dispatch (less economic withholding of capacity), with Eraring being the exception. Eraring suffers under this scenario compared with the BAU, as its portfolio was left unchanged and now faces increased competition from 4 other portfolios instead of 2.

Dispatch levels and portfolio capacity factors in the five portfolio scenario compared with the BAU scenario is shown in Table 14. This portfolio change also causes net imports into NSW to decline noticeably and NSW to become much more self-sufficient.

Table 14 **Change in dispatch, capacity factors and shares between the BAU and the five portfolio scenarios**

Energy source	2004/05	2005/06	2006/07	2007/08	2008/09
Change in energy supply to NSW (GWh)					
Bay swater	460	456	308	304	396
Lidell	349	402	338	363	325
Eraring	-168	-161	-143	-146	-140
Mt Piper & Wallerawang	363	362	329	281	418
Vales Pt & Munmorah	97	189	471	423	462
Generation from other NSW stations	-15	-22	-25	-31	-23
Net Imported energy	-1,115	-1,258	-1,308	-1,230	-1,425
Change in share of supply					
Bay swater	0.6%	0.6%	0.4%	0.4%	0.5%
Lidell	0.5%	0.5%	0.4%	0.5%	0.4%
Eraring	-0.2%	-0.2%	-0.2%	-0.2%	-0.2%
Mt Piper & Wallerawang	0.5%	0.5%	0.4%	0.4%	0.5%
Vales Pt & Munmorah	0.1%	0.2%	0.6%	0.5%	0.6%
Generation from other NSW stations	0.0%	0.0%	0.0%	0.0%	0.0%
Net Imported energy	-1.5%	-1.6%	-1.6%	-1.5%	-1.8%
Change in capacity factors					
Bay swater	1.9%	1.9%	1.3%	1.3%	1.7%
Lidell	2.3%	2.4%	1.9%	2.0%	1.8%
Eraring	-0.7%	-0.7%	-0.6%	-0.6%	-0.6%
Mt Piper & Wallerawang	1.8%	1.8%	1.6%	1.4%	2.1%
Vales Pt & Munmorah	0.8%	1.5%	3.0%	2.5%	2.7%

Data source: PowerMark modelling

The impact on station dispatch of adopting a seven, single station, portfolio structure compared with the five portfolio structure is to raise the dispatch of the all stations except Vales Point and reduce net imports into NSW. It appears as though Munmorah provides a backup to Vales Point in the five portfolio structure which allows that station to gain additional dispatch at the expense of Munmorah.

Table 15 **Change in dispatch between the five and the seven portfolio scenarios**

	2004/05	2005/06	2006/07	2007/08	2008/09
Bayswater	569	630	813	810	741
Lidell	-124	-120	5	28	36
Eraring	17	-15	-3	6	-13
Mt Piper	109	120	135	143	107
Munmorah	7	20	138	166	166
Vales Point	-70	-101	-437	-470	-358
Wallerawang	59	72	90	100	89
Other stations in NSW	-5	-7	-17	-20	-14
Net Flows into NSW	-569	-608	-737	-771	-751

Data source: PowerMark modelling

### Impacts on gross pool revenues

The higher dispatch by the five NSW generation portfolios causes a reduction in pool prices and as a result causes gross pool revenues to decline for all portfolios as shown in Table 16.

Table 16 **Change in gross pool revenue between the BAU and the five portfolio scenario**

	2004/05	2005/06	2006/07	2007/08	2008/09
	Change in gross pool revenue (\$ million)				
Bay swater	-86,230	-110,359	-272,329	-233,248	-240,059
Lidell	-66,949	-92,642	-244,965	-183,488	-203,957
Eraring	-34,524	-44,119	-176,580	-132,892	-154,629
Mt Piper & Wallerawang	-64,398	-77,414	-238,855	-203,947	-207,985
Vales Pt & Munmorah	-17,993	-29,966	-206,351	-157,885	-188,558
	Percentage change in gross pool revenue				
Bay swater	-11%	-11%	-28%	-25%	-25%
Lidell	-12%	-13%	-30%	-25%	-27%
Eraring	-8%	-8%	-32%	-27%	-30%
Mt Piper & Wallerawang	-9%	-9%	-28%	-25%	-25%
Vales Pt & Munmorah	-5%	-6%	-31%	-24%	-27%

Data source: PowerMark modelling

### comments on individual station portfolios

Having seven individual station portfolios further reduces pool prices as seen in Figure 12 although not significantly. This result assumes a similar level of contract cover on each station as in the five portfolio scenario and the BAU which is somewhat unrealistic.

Single station portfolios with only two generating units will face grave difficulty in carrying more than 50% hedge contract cover which, depending on their offer strategies, could result in a lower contracted market with higher pool prices. Furthermore, there are increased generator risks with individual stations and as such the five portfolios would seem to offer the better overall outcome for all stakeholders.

#### 4.4.5 Five portfolios with lower contract cover scenario

In this scenario, NSW portfolios are split into 5 (as detailed in Figure 10) and the contract level for the Bayswater portfolio is reduced by 5 percentage points.

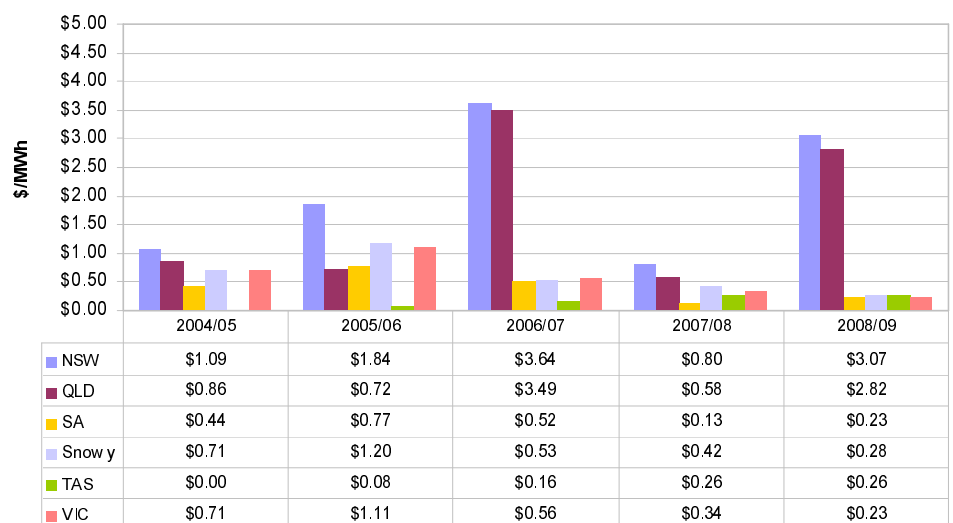
With the five portfolios, the ability of individual portfolios to influence the price is significantly reduced. This means that the five portfolios, with reduced market power, are much less likely to improve their position by running lower contract levels in order to push up pool prices. Bayswater, being the largest lowest cost portfolio of the five, has been chosen to test the effects of a

reduction in contract cover as it has the greatest prospect of achieving a sufficient increase in pool prices to justify such a move.

### Pool price impacts

A five percentage point reduction in contract cover on Bayswater in the five portfolio scenario, results in pool price increases of up to \$3.64/MWh in NSW compared with the five portfolios scenario. This is shown in Figure 13.

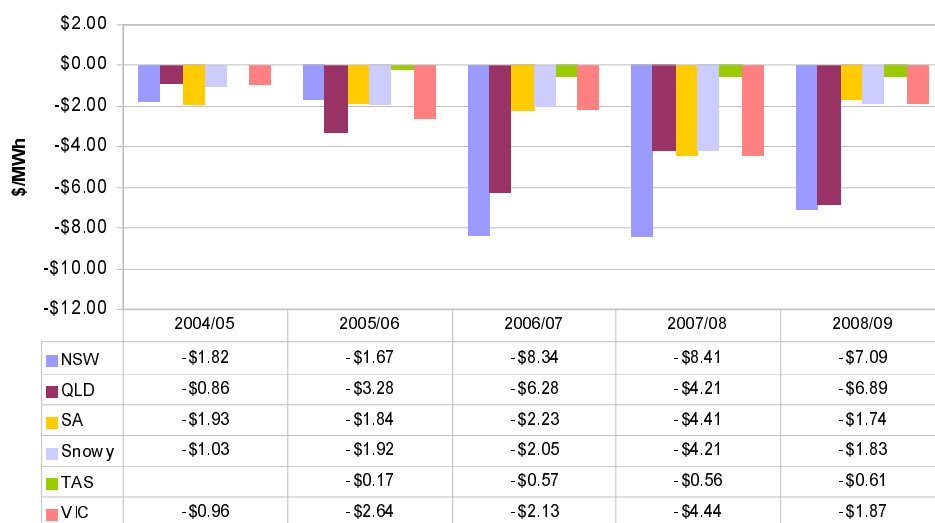
Figure 13 **Regional pool price changes resulting from lower contract cover on Bayswater in the five portfolio scenario**



Data source: PowerMark modelling

However, the increase in pool prices resulting from the reduced contract cover on Bayswater is not sufficient to offset the reduction in pool prices resulting in moving from three to five portfolios. This means that the five portfolios with a reduction in contract cover on Bayswater delivers pool prices which are lower than the BAU as shown in Figure 14.

Figure 14 **Regional pool price changes between the BAU and the five portfolio with lower contract cover (on Bayswater) scenarios**

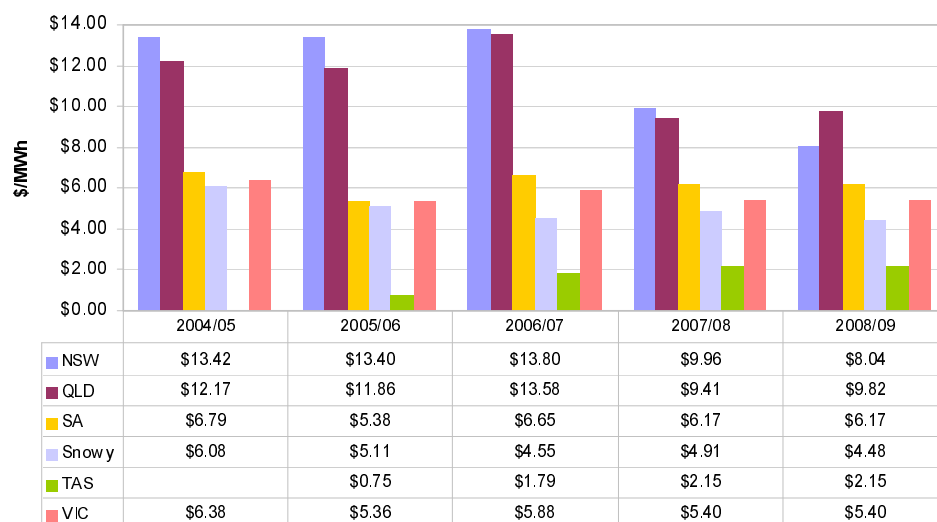


Data source: PowerMark modelling

In the very unlikely event that all five portfolios reduce contract cover by five percentage points then the increase in pool prices compared with the five portfolios scenario is shown in Figure 15. As expected, the change in pool prices due to lower contracts on all five portfolios is significantly higher than when only Bayswater has reduced contracts (compare Figure 13 with Figure 15).

However, more importantly, the increase in pool prices resulting from lowering contract on all five portfolios is very much less than the pool price increase resulting from a reduction in contract cover contract on the three large portfolios (compare Figure 9 with Figure 15). This is because the five portfolios do not have the market power to influence price to the same extent as the three large portfolios.

Figure 15 **Regional pool price changes resulting from lower contract cover on all portfolios in the five portfolio scenario**



Data source: PowerMark modelling

### Impacts on dispatch

The larger number of smaller NSW generation portfolios (5 instead of 3), combined with lower contract cover on Bayswater, has a relatively small impact on dispatch compared with the BAU. For Bayswater, the generally positive impact on dispatch of having five portfolios, is more than offset by the negative impact of its lower contract cover. The dispatch from stations other than Bayswater, however, generally benefits further by the lower contract cover on Bayswater. In line with higher dispatch from the NSW stations, net imports into NSW are noticeably lower than in the BAU.

Changes in dispatch and capacity factors compared with the BAU scenario, are shown in Table 17.

Table 17 **Change in dispatch, capacity factors and shares between the BAU and the five portfolio with lower contract cover (on Bayswater)**

Energy source	2004/05	2005/06	2006/07	2007/08	2008/09
	Change in energy supply to NSW (GWh)				
Baysw ater	-77	-95	-223	-282	-106
Lidell	406	435	381	396	365
Ering	-93	-116	-86	-86	-77
Mt Piper & Walleraw ang	413	392	375	326	443
Vales Pt & Munmorah	64	133	394	437	457
Generation from other NSW stations	-11	-17	-20	-23	-14
Net Imported energy	-722	-753	-846	-794	-1,057
	Change in share of supply				
Baysw ater	-0.1%	-0.1%	-0.3%	-0.3%	-0.1%
Lidell	0.5%	0.6%	0.5%	0.5%	0.4%
Ering	-0.1%	-0.1%	-0.1%	-0.1%	-0.1%
Mt Piper & Walleraw ang	0.5%	0.5%	0.5%	0.4%	0.5%
Vales Pt & Munmorah	0.1%	0.2%	0.5%	0.5%	0.6%
Generation from other NSW stations	0.0%	0.0%	0.0%	0.0%	0.0%
Net Imported energy	-0.9%	-1.0%	-1.1%	-1.0%	-1.3%
	Change in capacity factors				
Baysw ater	-0.3%	-0.4%	-0.9%	-1.2%	-0.4%
Lidell	2.6%	2.6%	2.1%	2.2%	2.0%
Ering	-0.4%	-0.5%	-0.4%	-0.4%	-0.3%
Mt Piper & Walleraw ang	2.0%	1.9%	1.8%	1.6%	2.2%
Vales Pt & Munmorah	0.5%	1.1%	2.5%	2.6%	2.7%

Data source: PowerMark modelling

### Impacts on gross pool revenues

The lower NSW pool prices in the five portfolio scenario (see Figure 14) more than offset the generally higher dispatch (see Table 17) to produce lower gross pool revenues as shown in Table 18. Thus, having five portfolios was sufficient to contain the market power observed in a three portfolio structure.

Table 18 **Change in gross pool revenue between the BAU and the five portfolio with lower contract cover on Bayswater scenarios**

	2004/05	2005/06	2006/07	2007/08	2008/09
	Change in gross pool revenue (\$ million)				
Bayswater	-62,407	-72,536	-198,157	-215,406	-181,578
Lidell	-47,302	-53,376	-165,012	-167,389	-134,242
Eraring	-18,746	-18,430	-122,499	-122,128	-110,859
Mt Piper & Wallerawang	-38,300	-35,607	-158,113	-189,021	-144,928
Vales Pt & Munmorah	-1,230	-6,111	-137,641	-142,360	-136,625
	Percentage change in gross pool revenue				
Bayswater	-8%	-7%	-20%	-23%	-19%
Lidell	-9%	-7%	-20%	-23%	-18%
Eraring	-4%	-4%	-22%	-25%	-21%
Mt Piper & Wallerawang	-6%	-4%	-18%	-23%	-17%
Vales Pt & Munmorah	0%	-1%	-21%	-22%	-20%

Data source: PowerMark modelling

## 4.5 Modeling summary

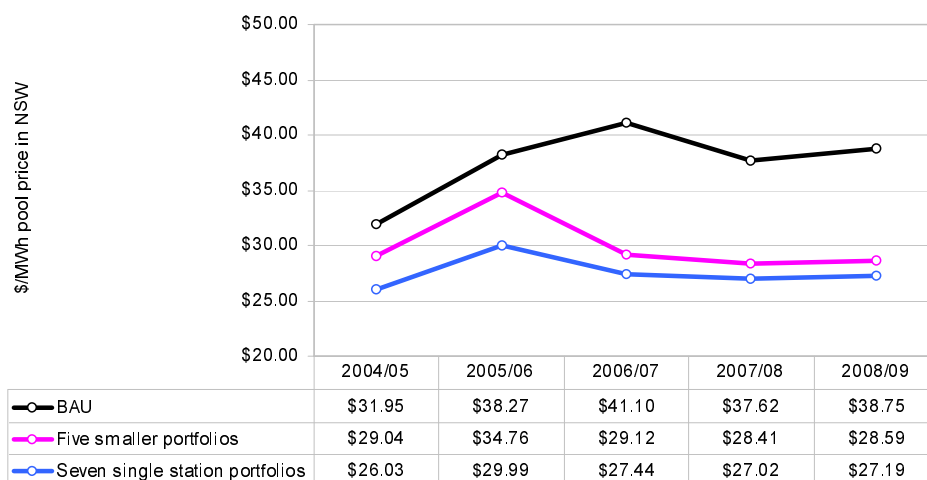
The results of the modeling presented above highlight a range of potential benefits and dangers in the implementation of the proposed Scheme.

The biggest potential benefit from the Scheme is for dilution of market power through offering smaller portfolios to private traders. Moving to a five portfolio structure results in reductions in pool prices of between \$3 and \$12/MWh over the 5 year period. This is illustrated in Figure 16.

Figure 16 shows that there is a significant pool price benefit gained through a reduction in market power in moving from a three portfolio structure to five portfolio structure. Moving to seven portfolios does not deliver much more, in terms of lower pool prices, than the five portfolio structure. On this basis, the modeling strongly supports a five unit portfolio structure.

Furthermore, with four generating units in each portfolio, the five portfolio structure would allow each portfolio to run reasonable levels of contract cover, unlike the seven portfolio structure, where four of the portfolios would only consist of two units thereby seriously affecting their ability to service reasonable contract levels.

Figure 16 **NSW pool prices under different portfolio structures**



Data source: PowerMark modelling

This large reduction in pool prices over the BAU scenario, by moving to a five portfolio structure, highlights the degree to which the current three portfolio structure keeps prices artificially high over the projection period.<sup>6</sup> In this respect, the proposed scheme offers the potential for the effective breakup of the portfolios without the community and industry resistance of privatization and is strongly recommended by the EUAA..

However, there are a range of potential dangers to consumers that also stem from the Scheme. The largest of which is the potential for exercise of market power — particularly if the current portfolio structure is maintained. As shown in the modeling, significantly higher price outcomes are possible through relatively minor changes to offer strategies of the large NSW portfolios. In addition, the impact of fixed fuel charges (ie: not based on usage), may result in slightly lower average pool prices and increased pool price volatility.

In particular, the modeling shows that NSW pool prices are likely to increase by between \$5.00 and 15.00/MWh, (see Figure 17) should the three major portfolios be retained and the largest of them, MacGen, decided to reduce contract cover by as little as five percentage points and use the resultant increase in discretionary capacity to game the market. This would be a very tempting strategy to a large portfolio if the resultant pool price was above the available contract price.

Having a five unit portfolio structure reduces the ability of any one portfolio to reduce contract cover and game the market. Figure 17 shows that, with a five

<sup>6</sup> This fact was identified by COAG Energy Markets Review in 2002, which recommended the break-up of the NSW portfolios.

portfolio structure, a five percentage point reduction in the largest portfolio (Bayswater) increases price by less than \$4.00. The added protection against use of market power of moving from a five to a seven portfolio structure is minimal as shown in Figure 17.

Figure 17 **Changes in the NSW pool price from reductions in contract cover under different portfolio structures**



Data source: PowerMark modelling

## 5 Findings

### 5.1 General

The Scheme has the potential to increase electricity prices to consumers through changes in approach by private generator traders to offering the NSW power stations into the NEM and negotiating hedge contracts with retail managers. There are a number of essential elements the Scheme must incorporate in order to minimise this possible outcome including realistic reserve prices and smaller generation portfolios. Only then does it have the potential to benefit users and is therefore a proposal that users should seriously consider supporting.

#### 5.1.1 Conflict of interest

The NSW Government faces a serious conflict of interest in choosing between extracting as high a price as possible for the generator trader and retail manager contracts and delivering competitive electricity prices for NSW consumers. In this regard, in setting the reserve prices for the generator traders and retail managers the NSW Government should consider that people and businesses, as electricity consumers, gain a greater and more direct consumer surplus from lower electricity prices than, as taxpayers, through higher returns from state-owned generators and retailers. The NSW Government needs to clarify this and its policy position on the choices involved.

#### 5.1.2 Risk and the market

The Scheme is strongly focussed on reducing Government electricity market price volatility risk exposure, with little apparent concern for providing ongoing reductions in real prices and quality of supply to electricity users, and encouraging greater DM.

In fact, the price volatility risks, which seem to be the main focus of the Scheme, can be adequately managed by financial hedges provided that appropriate counterparties are available for wholesale energy trading. It needs to be recognised that private participants are really no better equipped than state-owned participants to handle other more fundamental market risks such as the balance between supply and demand, equipment failure and adverse weather.

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In fact, modelling suggests that, if the Scheme is not appropriately devised its objective of reducing NSW taxpayers exposure to risk through contracting out

trading rights may actually increase NEM risks. Hence, even though NSW people will face less risk from trading as taxpayers, they may face greater NEM risks as electricity end users.

### 5.1.3 Approach to market power

Of major concern to consumers is the possible exercise of market power if the three large generation portfolios in NSW are each transferred to the private sector. This would place an unacceptable level of market power in private control resulting in higher electricity prices than would have occurred in a more competitive environment.

To provide an enhanced outcome for electricity users, serious consideration needs to be given to splitting the portfolios in the auction to at least five (rather than three), even if that means a lower price is paid for the capacity by the private traders.

Market modelling clearly shows that, private generator traders with control of the three large generation portfolios, have a far greater opportunity to game the market to produce higher prices simply by running lower contract levels than they would in a more competitive setting with smaller portfolios.

Having the same private sector entity with control of both a generator trader and a retail manager, provided there is sufficient generation and retail competition, and the price paid for the trader and retail businesses is not excessive, could well benefit electricity users. This would be achieved by delivering lower pool and hedge contract prices by removing the need for much of the trading operation.

However, allowing combined generation and retail businesses is likely to reduce the depth of the financial hedge market thereby increasing the price risk for retailers without generation. This is because competitive hedge contract counterparties will be more difficult to find and hedge contract prices are likely to be higher.

### 5.1.4 The auction process and price paid

The auction process, by allowing multiple bids for any combination of generator traders and retail managers, could be problematic for government from a probity perspective with many possible bid combinations potentially raising serious issues. The process may well drag on for many months, creating an unacceptable outcome for electricity consumers.

There is the risk that high reserve prices, if known prior to the auction, could force up bid prices, which will lock the private traders into seeking higher prices from electricity users than are currently prevailing. It is critical,

therefore, that the reserve prices should not be revealed to bidders before the auction.

## 5.2 Generator trader

### 5.2.1 Portfolios and market power

Passing control of the generation capacity of each of the three large generation portfolios to individual private generator traders has potential to provide the traders with unacceptable market power. This problem could be avoided by offering smaller parcels of generation capacity.

Offering smaller portfolios is also likely to open the market to a greater number of existing and potential generator traders, particularly where market power could be an issue for existing generators, which could be excluded from the auction of large portfolios by *Trade Practices Act* requirements.

Market modelling shows that a five portfolio split, with Delta and Macquarie split into two, would provide adequate competition and restrict the exercise of market power. Even if the largest of the five generator traders, Bayswater, were to attempt to game the market by running a 5% lower contract cover, the pool prices would still be lower than under the BUA.

While modelling also shows that moving to a seven portfolio structure does not provide sufficient additional protection against abuse of market power to warrant moving to such a structure. The seven portfolio structure, based on a single station in each portfolio, would mean that four of the seven portfolios would contain only two generating units and hence not be able to run adequate contract levels.

### 5.2.2 Compensation for generator failure

Compensation payments to private generator traders in the event of a catastrophic failure will add to the cost of producing electricity, which will be to the ultimate cost to consumers. Under the current arrangements, responsibility for providing generator backup for hedge contracts could be simply transferred to another generation portfolio, which has spare capacity, without significant additional cost to the taxpayer while the generator is repaired.

In view of this, the Government should make provision in the generator trader contracts for such a generator failure. This could be done either through some form of compensation to traders or by withholding some capacity from the traders to cover this possibility. If provision is not made for this type of failure then traders are likely to discount the prices offered for the trader contracts.

### 5.2.3 Lowering in market discipline on generators

Probably the most disappointing aspect of the Scheme for electricity users, is that the cost discipline imposed on generators by a competitive market is likely to be significantly reduced. The need to be competitive in the market, to ensure survival, is an irreplaceable incentive for generators. This has been one of the most striking areas of improvement since commencement of the NEM and is an ongoing process with generators constantly striving to improve efficiencies and reduce costs wherever possible. The market discipline also includes the constant threat of low cost new entrants.

This market discipline would be very difficult if not impossible to replicate through five year contractual obligations. This is because, in order to achieve the critical efficiency improvements, generators need a multitude of flexible strategies in order to respond to constantly changing market circumstances. The Scheme seems to recognise the importance of generator efficiency in delivering positive market outcomes, but its proposal that the trader contracts include a requirement that generators maintain existing levels of availability, falls well short of what is required for competitive market operation.

### 5.2.4 Fuel supply and market trading

Matching fuel supply arrangements to offer strategies is a critically important aspect of trading in the market, which will be largely lost under the Scheme. Linking trading and fuel acquisition provides a strong incentive to seek lower cost fuel supplies and coal quality characteristics are considered in a commercial rather than purely operational setting. Furthermore, under the Scheme there is only very limited incentive on state-owned power station operators to arrange competitive longer term fuel purchases

The proposed three tiered pricing structure currently proposed by incorporating a periodic payment, assumed to cover the take-or-pay portion of existing coal contracts, may lead to private generator traders regarding this coal as having a zero marginal cost.

Modelling of the effects of the NSW private generators traders offering the contracted capacity at zero results, as expected, in marginally lower pool prices. Dispatch of the power stations, however, increases so the gross pool revenue of the NSW generators is surprisingly largely unchanged.

### 5.2.5 Market approach

One clear option available to a private trader would be to reduce the level of contract cover and attempt to game the market to force up prices. The main obstacles working against this strategy is the current excess supply (although

this will reduce with ongoing load growth) and possibly the price and/or take-or-pay volume of coal. Another factor working against such a strategy is the strong desire of retailers to carry high levels of contract cover to mitigate the market price risks. In seeking these high levels of cover, however, retailers may be prepared to increase contract prices and margins which has a similar adverse outcome for electricity users as higher pool prices.

Modelling of the impact on prices of a five percentage point reduction in contract cover by all three NSW generation portfolios, gives a substantial boost to annual average NSW pool prices of between \$13.00 and \$29.00/MWh compared with business as usual.

### **5.2.6 Term of the generator trader contract.**

It is difficult to envisage a seamless electricity hedge market under the proposed five year term for the generator trader contracts, even with the next five year period trader contract let well in advance. What is more likely is a decline in the availability of hedge contract cover as the expiry of the generator trader contract approaches its expiry date.

This is one of the prime dilemmas of the Scheme as a solution which is fair to all parties (ie government, incoming trader, out going trader and customers) and delivers a seamless transition from one trader to another in terms of the hedge contract market. No viable solutions are offered in the Further Discussion Paper.

### **5.2.7 Treatment of ETEF**

The ETEF is a significant market distortion, which may have greater potential to cause higher prices in the NEM under the Scheme, when private generators have control of NSW generating capacity, than under existing arrangements.

The ETEF reduces the contract cover carried by private generator traders which will effectively allow a higher degree of freedom for them to game the market to achieve higher pool prices.

However, the private generator traders will be somewhat restricted in how they offer the ETEF component of their capacity as, when pool prices are above the ETEF regulated energy cost (REC) and the balance in the fund is depleted, the generator trader will be required to make weekly payments to the fund to the amount of any deficit.

In fact, there is a strong incentive for the generator traders to be dispatched for the ETEF component of capacity when pool prices are more than the REC in order to be accumulating funds to top-up the ETEF as required. This means that the maximum price likely to be offered for this ETEF capacity will

generally be less than the REC. However there is also a strong incentive for the generator trader to push pool prices as close to the REC as possible, but in a oversupplied market this has been impossible.

In general, apart from the few occasions when strategic withdrawal has been used to create price spikes to claw back the funds in the ETEF, the state owned generators have offered the ETEF component of capacity in to the market at their SRMC to ensure dispatch, in a similar way to ordinary hedge contracts.

## 5.3 Retail manager

### 5.3.1 Transfer of customer to private retailers

The high retention of contestable customers by state-owned retailers suggests that private retail managers may be unable to offer prices as low as those currently available from the state-owned retailers. If so, then forcible transfer to a private retailer will disadvantage contract customers.

The electricity users could be adversely affected if the successful private entity was to pay a high price for retail manager contracts and then recover the payment from customers. Of course, assuming there is a competitive retail sector, the retail managers will need to compete for customers with other retailers, so will be somewhat restricted in the extent they will be able to pass on these additional costs. It is imperative; therefore, that effective competition in the retail sector is fostered.

### 5.3.2 Term of retail manager contracts

It is difficult to envisage how the government will be able to re-auction the retail manager contracts as inferred in the Further Discussion Paper. The retail manager contracts effectively expire as the electricity customers' contracts with the state-owned retailers expire. The only customers that could be pulled back for a further auction after five years would be those whose contracts with the state-owner retailers have not expired, although there are likely to be relatively few of these.

In a similar way, most hedge contracts transferred from the state-owned retailers will have expired and so there would be very little of these to auction at the next round.

The transfer of these contract customers should be permanent with the state-owned retailers servicing only customers choosing to remain on regulated tariffs. Holding an auction each five years is not only unrealistic but would

remove the incentive for the retail managers to build the business by providing superior service to customers.

### **5.3.3 Importance of bilateral contracts**

Bilateral contracts, particularly those between state-owned generators and state-owned retailers, normally carry prices that are below those of traded, over-the-counter, contracts and electricity futures. They allow the retailers to offer lower retail prices to contract customers.

With the sale of the generator trader contracts, particularly if these are paired with retail manager contracts, the lower prices currently available through bilateral contracts are likely to either not be available to the retail managers, or only available to those retail managers linked with a generator trader. This has potential to increase electricity prices and/or allow selected private retail managers to gain market advantage and increase market share.

### **5.3.4 Effects of forced transfer**

The needs of electricity users on existing retail contracts should be protected so that, if a private retail manager fails to provide satisfactory service, they have proper recourse to take the matter up with the state-owned retailer and, if necessary, be transferred to another private retailer of their choosing.

### **5.3.5 Greenhouse issues**

Given that the state-owned retailers will still have responsibility for the greenhouse schemes for franchised customers, there is the obvious temptation to retain only the most cost effective greenhouse abatement schemes and transfer the higher risk, more expensive schemes to the private retail managers. Not only would such an approach place the private retail managers at a financial disadvantage with other private retailers, but it has potential to result in increased electricity prices.

It is important that the abatement schemes, to be passed to the retail managers, be clearly identified so that the bidders are able to reflect this in the prices offered.

### **5.3.6 Demand management (DM)**

Unfortunately DM is not fostered by the Scheme, even though it could offer a lower cost solution than adding further generation capacity.

DM is not attractive to retailers as it involves a reduction in sales, which impacts negatively on retailers' revenues and profits and there are no additional incentives under the Scheme for retailers to pursue DM.

In principle, the network service providers could have more directly to gain from DM through reduced capital requirements but until the recent IPART decision on distribution pricing there were no incentives for these businesses to implement such schemes. Also, without access to customers in the same way as retailers, the network service providers will struggle to achieve significant advances with regard to DM. Moreover, by splitting the retail and distribution services, the Scheme may further reduce the ability of distributors to implement DM schemes.

DM is largely neutral from the existing generators' perspective. DM may reduce the overall level of available hedge contract cover and by freeing-up capacity, provide opportunity for the generator traders to game the market. However, by reducing demand, DM limits the ability of the generators to increase pool prices. Most importantly from a generation perspective, DM, by reducing peak load, defers the need for additional capacity thereby providing cost savings to consumers.

## 6 Recommendations

The following recommendations have generally been formulated from an electricity users' perspective. They show how the key features of the Scheme would need to be addressed in order for the scheme to be acceptable to electricity users and to preserve the critically important characteristics of the competitive market.

The recommendations provide a constructive approach to the development and implementation of the Scheme which, if adopted would enhance the positive aspects of the Scheme as well as addressing electricity user concerns.

- Recommendation 1. At least five (not three) generation portfolios be offered to private generator traders to mitigate potential market power.
- Recommendation 2. Reserve prices to be kept secret and set to achieve an appropriate balance between auction returns and competitive electricity prices not just to maximize government returns.
- Recommendation 3. All existing and new coal contracts should be under the total control of the private retail trader, with any new contracts extending beyond the expiry of the trader contract to be approved by government and pass back to the government at expiry of the generator trader contract.
- Recommendation 4. Encourage ongoing increased efficiency in the power station operation in the generator trader contracts with appropriate incentives and penalties payable by and to the generator trader.
- Recommendation 5. To foster the development of a deeper financial hedge market, a limit should be placed on the amount of generation capacity which can be paired with retail traders.
- Recommendation 6. In recognition of the importance of retail competition, the Scheme should award the retail management contracts to no less than three separate retailers.
- Recommendation 7. Further detailed consideration be given to the likely adverse effects on the hedge market of the expiry of the five year generator trader contracts; and develop and publish mitigation strategies before proceeding with the Scheme.

- Recommendation 8. Provide an option for contract customers to transfer to a retailer of choice, if there is unsatisfactory performance by the chosen private retail manager.
- Recommendation 9. Provide, up-front, the rules which will govern the letting of the trader contracts, including the process to be used to compare bids.
- Recommendation 10. Clearly define the approach to be taken with transfer of greenhouse gas abatement contracts.
- Recommendation 11. That the tender documents for the generator trader and retail manager contracts incorporate a request for bidders to outline the DM strategies that they intend to adopt and that these responses be given an appropriate weighting in the bid evaluation process.
- Recommendation 12. Ensure that DM is adequately addressed in the proposed NSW SOO by including an assessment of DM opportunities and appropriate incorporation in the load forecast.
- Recommendation 13. Consideration should be given to applying the ETEF funds to encourage greater DM by state-owned retailers.

## A Outline of PowerMark

PowerMark has been developed over the past five years in parallel with the development of the NEM. The model is used extensively by ACIL Tasman in simulations and sensitivity analyses conducted on behalf of industry clients.

PowerMark is a complex model with many unique and valuable features. It provides insights into:

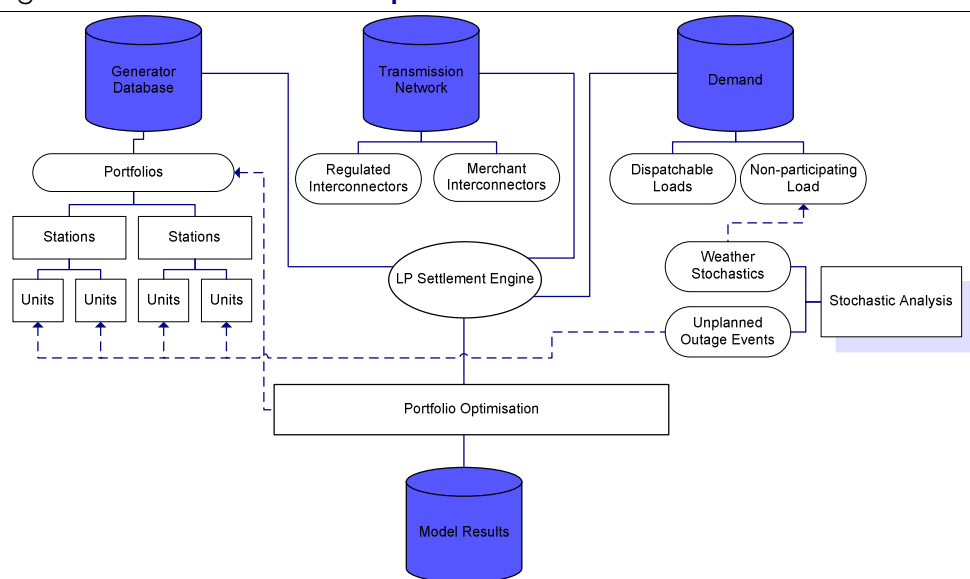
- wholesale pool price trends and volatility;
- variability attributable to weather/outages and other stochastic events;
- market power and implications for generator bidding behaviour;
- network utilisation and generation capacity constraints;
- viability of merchant plant and regional interconnections;
- contract and price cap values;
- timing, size and configuration of new entrant generators;
- demands for coal, gas and other fuels; and
- the cost outlook for buyers of wholesale electricity.

PowerMark effectively replicates the NEMMCO settlement engine — SPD engine (scheduling, pricing and dispatch). This is achieved through the use of a large-scale LP-based solution incorporating features such as quadratic interconnector loss functions, unit ramp rates, network constraints and dispatchable loads. The veracity of modelled outcomes relative to the NEMMCO SPD has been extensively tested and exhibits an extremely close fit.

In accordance with the NEM's market design, the price at any one period is the cost of the next increment of generation in each region (the shadow or dual price within the LP). The LP seeks to minimise the aggregate cost of generation for the market as a whole, whilst meeting regional demand and other network constraints. Figure A1 is a simplified diagrammatic representation of the model and its methods of combining input data from the supply and demand modules to produce a price and dispatch result for each region and power station for each period.

PowerMark is very flexible. Additional elements, such as regions, interconnectors, generators or loads can be easily added and their characteristics varied through time. PowerMark has been applied to several different market designs — gross pools, net pools, regional and nodal structures.

Figure A1 **PowerMark conceptual framework**



Data source: ACIL Tasman, PowerMark documentation

A distinctive feature of PowerMark is the inclusion of a portfolio optimisation module. This optional setting allows selected portfolios to seek to maximise net revenue positions (taking into consideration contracts for differences) for each period. These modified generator offers are then resubmitted to the settlement engine to determine prices and dispatch levels. Each period is iterated until a convergence point (based on Nash-Cournot equilibria theory) is found.

The benefits of the optimisation module are twofold:

- portfolios structure their generation offers in an economically rational way. From past experience, this optimisation process generates strategies which align with the behavioural reality in the marketplace; and
- second-round effects from fundamental changes to the market — such as the addition of a new entrant generator or creation of additional regions, can automatically be incorporated without imposing explicit constraints or directions for incumbents.

PowerMark can be configured to run at varying time intervals — from 5 minutes (288 period days) through to 180 minutes (8 period days). Typically the model is run hourly or half-hourly to meet client requirements and establish a reasonable price resolution.