



Energy Reform Implementation Group

**Review of Energy Related
Financial Markets
Electricity Trading**

November 2006

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1 Executive summary

On 10 February 2006 the Council of Australian Governments (“COAG”) established a high-level Energy Reform Implementation Group (“ERIG”) chaired by Mr Bill Scales AO and including industry experts (Mr Geoff Carmody, Mr Alan Rattray and Mr David Swift) to develop detailed implementation arrangements for further energy market reforms.

ERIG must report back to COAG before the end of 2006 with proposed policy measures to:

- achieve a fully national transmission grid;
- address any structural issues affecting the competitiveness of the sector; and
- ensure that there are transparent and effective financial markets to support energy markets.

ERIG’s report will set out the case for or against further policy measures.

On July 2006 ERIG published an Issues Paper for public comment and received over forty submissions.

ERIG engaged KPMG to assist in formulating its views on the development of energy-related financial markets by examining three issues in detail. The issues are described in section 2.

This report presents the findings and recommendations of our study on the state of the energy-related financial markets in Australia with particular reference to electricity trading in the National Electricity Market (“NEM”), and impediments to their development.

The key findings and recommendations from this study are set out below and examined in the body of this report.

1.1 Financial trading in the NEM (section 4)

- Financial market trading continues to develop depth with positive implications for building liquidity and improving price transparency. However:
 - trading largely remains an asset-based market between merchant generators¹, increasingly vertically integrated energy retailers and larger customers due to the minimal but expanding presence of financial intermediaries and non-asset-backed participants operating in the derivative markets; and
 - liquidity is concentrated at the short-end of the forward electricity price curve out to three years. This period corresponds to active trading in electricity futures contracts and broker intermediated contracting in the over-the-counter market.
- Improving liquidity and price discovery is evidenced by:

¹ Defined as generators with no or minimal interest in retailing businesses

- re-launch of SFE futures contracts in 2002 leading to a dramatic increase in trading volumes to date;
- the emergence of new energy retailers in the NEM using the financial markets to manage electricity price and load risks further contributing to liquidity²; and
- the expanded role of brokers and participation of a broader range of financial institutions and integrated and global energy businesses in trading activity.

Limited price transparency in the bilateral contract market remains an issue.

- While this market-wide development is encouraging and reflects the natural dynamics of market-based solutions, liquidity is not uniform and still broadly confined to segments of the forward curve out to three years, certain NEM regions and trading in vanilla base-load products. Lack of liquidity is particularly evident in:
 - South Australia (and potentially Tasmania given the concentration of the market in the state); and
 - cap and structured flexing products.

The NEM also exhibits a tendency to be regionalised due to poor performance and generator bidding practices.

- Financial hedging arrangements such as ETEF (NSW) and LEP (Queensland) exacerbate the issue of concentration of energy businesses owned by state governments with an adverse impact on liquidity in the contracting market.
- Energy retailers continue to invest in building or controlling peaking capacity to manage demand-induced price spikes as an alternate solution to financial products – this is not necessarily a failure of the short-term contracting market but indicative of broader cost of capital and integrated business strategies. Conversely, merchant generators are supporting the establishment of new retailing ventures further evidencing the trend towards vertical integration in the NEM. Vertical integration has had a marginal impact on the contracting market to date. Planned investment in generation assets together with merger and acquisition activity associated with the sale of state government owned energy businesses in Queensland and potentially in New South Wales may significantly increase the degree of vertical integration in the NEM leading to a more pronounced impact on market liquidity over time.
- The removal of ETEF will progressively add depth and significant liquidity in the NSW regional pool and more broadly across the NEM through inter-regional trading as generators and retailers substitute ETEF for bilateral arrangement. In the case of Queensland, the removal of LEP is more immediate in its impact on the contracting market following the state government's decision to sell its retailing businesses. Importantly, the sale will have implications for credit risk management practices and the assessment and pricing of credit

² Refer Figure 40, Section 7.2.1 for details of new entrants

default risk in the contract market as state-owned merchant generators are increasingly exposed to non-government rated, vertically integrated energy groups.

1.2 Environmental products (section 5)

- Government hesitation in implementing a national emissions trading scheme has resulted in a number of fragmented, largely state-based schemes that encourage compliance-based transactions and generally do not promote active trading and speculation that promote market liquidity.
- Existing schemes have encouraged structured physical and physically related power projects that often provide bundled electricity supply and environmental products such as RECs and NGACs to the purchaser. These structures can be quite significant in size and yield a substantial number of environmental entitlements but are transacted bilaterally and hence are not typically transparent.
- The EU Emissions Trading Scheme (ETS) is a useful market from which comparisons and lessons for the evolution of the Australian environmental markets can be drawn. Whilst there have been a few technical and operational issues that have needed to be addressed over time it is clear that this scheme has been successful in encouraging and facilitating emissions trading in Europe. The inter-relationship (correlation) between carbon prices under the ETS and electricity and gas prices has created interesting cross-market dynamics and has also encouraged integrated trading/hedging across each of these. This is a key dynamic that is not as prevalent in Australia.

1.3 Inter-regional trade and SRAs (section 6)

- Submissions to ERIG acknowledged the issue of lack of firmness with the debate centred on the policy response to firming the SRA process and potential risks of introducing major changes, particularly in isolation to initiatives to improve transmission performance. While historically the residues distributed have exceeded auction proceeds, this outcome is not surprising as auction participants bid for the right to receive uncertain future cash flows over time. In many respects, the shortfall simply reflects the financial market's pricing of the lack of firmness in SRAs rather than a reflection of a weakness in the auction process itself.³

³ The difference between the value of electricity in the region where it is generated and its value when sold in a different NEM region is called the inter-regional settlement residue (IRSR). The IRSR that accumulates is made available to the market by the conduct of a quarterly auction. The auction provides participants with a mechanism to manage the risk associated with different price outcomes between trading regions. The volume of IRSR available through the auction depends on the actual level of interconnector flows which may, on occasion, demonstrate a high level of variability. Consequently IRSR auction units may be less firm tools for risk management than other types of financial instruments available to market participants. P 31, *Trading Arrangements in the NEM*, NEMMCO

1.4 Vertical and horizontal integration in the NEM (section 7)

- Vertical and horizontal integration is increasingly a defining characteristic of the developing and evolving electricity market driven by corporate strategies to create shareholder value from asset portfolios and financial and capital market incentives to reduce cost of capital. In this regard, the three integrated private sector energy retailing groups operating in the NEM share common business strategies.
- The sale of government owned retailing businesses is likely to promote further consolidation in the NEM and reinforce the focus on building and controlling the despatch of peaking plants to manage aggregated load risks.
- In many respects, horizontal integration poses more challenges for the NEM both in terms of leaving state-based government-owned merchant generators reliant on the bilateral contracting market with NEM retailers to manage price risk and cash flow volatility and, secondly, the effectiveness of the NEM prudential framework in detailing with credit-induced event risk in the NEM.

1.5 Government intervention (section 8)

- A key recommendation of the Parer Review was the removal of ETEF (in NSW) and BPA arrangements (in QLD) irrespective of whether retail price caps are removed.
- This reform is now in train with the recent announcement of the NSW state government to remove ETEF by 2010 and the decision by Queensland to sell its energy retailing businesses and so lead to abolition of BPA. Both actions will be positive for financial market development.
- Removal of retail price caps for the majority of customers will also have broad positive effects on the efficiency of electricity markets.

1.6 Credit risk in the NEM (section 9)

- The cost of credit support does not have a major bearing on the level of profitability of the sector although the cost is disproportionately higher for capital constrained newer entrants. In our view, access to capital rather than the cost of credit support under the existing prudential framework is the more substantive barrier to entry for new entrants.
- The separation of spot and forward markets in calculating the level of credit support provided to NEMMCO leads to an inefficient use of participants' economic credit capital. This inefficiency arises because there is no effective mechanism to facilitate the set off of hedge positions with settlement exposures on underlying spot market transactions leading to the circular cash flows occurring between the spot and forward markets.
- The exposure to credit default risk on bilateral contracts can exceed the spot settlement risk given their duration and effect of changes in the level of spot prices over time.

- Overseas energy markets have evolved towards integrating wholesale spot and forward markets under a common clearing system to reduce settlement risks and promote more efficient use of economic credit capital. The transfer of ownership of state owned energy assets to the private sector will lead to concentration of credit default risk resulting from horizontally integrated energy retailing businesses operating across the NEM and is likely to generate significant focus in the near-term.
- NEMMCO and the SFE have submitted proposals to the Australian Energy Market Commission (“AEMC”) seeking amendment to the National Electricity Rules (“Rules”) on Settlement Reallocations. The SFE proposal or a variant of the proposal resulting from the current consultation process, if codified in the Rules, will reduce the level and cost of credit support without compromising the integrity of the prudential framework. Importantly, the proposal is an important first step towards facilitating the integration of spot and exchange-traded forward markets, promoting the establishment of a common clearing system under a single entity as a logical development of the NEM in line with international precedents in electricity markets.

1.7 Demand side management (section 10)

- The Parer Review in 2002 made several recommendations to improve the utilisation of demand side management (“DSM”) in the NEM and deliver a range of benefits in energy risk management as well as potentially deferring investment in infrastructure. Since the Parer Review, there has been limited growth in utilisation of DSM which is mainly restricted to large contestable energy users. The mass market has significant potential but is largely untapped. The factors contributing to this current state are varied and include the following.
- DSM activities are currently difficult to capture and administer in practice leading to higher transaction costs compared to other risk management solutions to manage retail load risks.
- The lack of a liquid, transparent short-term derivative market makes DSM difficult to value further dampening the price signals crucial to providing incentives to contestable customers.
- Retailers are the main beneficiary due to the physical nature of DSM reducing the financial incentive for large contestable customers to provide firm commitments.
- The non-firm nature of demand side load reduction remains a key issue for retailers reducing the value of DSM as a viable structural hedge of load risks compared to the contracting market or investment in generation assets.
- The recent decisions to abolish ETEF and LEP arrangements in conjunction with the proposed sale of retail businesses in QLD are positive steps for the NEM with potential benefits for DSM as improved liquidity in the short-term derivative market (particularly the day-ahead and week ahead) will provide the price signals essential for encouraging increased utilisation of DSM.

1.8 Recommendations

Section 4 – Energy related financial markets in Australia

- Financial markets are evolving in line with the maturity of the NEM and, in our view, will continue to do so without the need for further government intervention or policy reform.

Section 5 – Environmental markets

- The existing renewable energy schemes should be replaced by the adoption of a national emissions trading scheme that is capable of being implemented in a timely manner and integrated into a global scheme in the future. This issue has been examined as part of the accompanying report on Capital Markets and Investments which found a need for a consistent policy to price carbon emissions.

Section 6 – Inter-regional trade

- Firming up SRA's through the re-design of the instrument (e.g. using auction proceeds to support price differences in conjunction with other arrangements to underwrite risk), conceptually, has merit and requires further analysis. However it is essential that the analysis considers the extent of changes to SRA prices, implications for financial link ratings, management of residual exposures to NEMMCO and parties involved in firming SRAs.
- Potential enhancements to the SRA instrument

Changes to the existing SRA instrument to promote inter-regional trade and risk management may include the following:
 - Shorter-term SRAs
 - Longer-term SRA units
 - Peak and Off-peak SRAs
- Potential changes to the SRA process
 - ERIG to commission a detailed analysis of the introduction of "firmer" SRA's and CSP/CSC schemes to fully assess the physical and financial implications of firming proposals and the risks, costs and benefits to participants and customers as opposed to allowing developments in transmission planning and operation combined with the gradual withdrawal of government ownership of energy businesses in the NEM and competitive forces to provide a market-based solution.
 - NEMMCO to consider the introduction of short and longer -term SRA's as well as Peak/Off-peak products if there is sufficient support by participants. It is essential that

proposals to change the SRA process take into account physical and financial market issues that impact on inter-regional trade.

Section 7 – Vertical and horizontal integration in the NEM

- Vertical integration is often viewed as the basic problem of market liquidity this issue should be left to market forces and the existing regulatory framework for dealing with competition issues to resolve.

Section 9 – Credit risk and prudential framework

- We believe the SFE proposal is a positive initiative providing participants with an efficient mechanism to reduce the cost of credit support.
- A full assessment of the benefits of establishing a common clearing system for the electricity market is warranted for the NEM. As noted in Table 9, overseas energy markets have evolved towards integrating wholesale spot and forward markets under a common clearing system to reduce settlement risks and promote more efficient use of economic credit capital.

Section 10 - Demand side management

- The Parer Review made a number of recommendations designed to allow utilisation of DSM by participants to evolve through competitive market forces that are still relevant today. These recommendations relate to:
 - the removal of price caps to encourage competition in the residential sector and provide the incentive for energy retailers, distributors, end-users and other parties to more effectively utilise DSM capacity and reduce its transaction costs; and
 - implementation of interval/smart metering at the residential level.
- Facilitation of improved liquidity in the short-term derivatives market and continued growth of the SFE futures market will provide increased price transparency that will assist in valuing DSM and encourage further participation amongst energy users and participants across the NEM.

2 Introduction

On 10 February 2006 the Council of Australian Governments (“COAG”) established a high-level Energy Reform Implementation Group (“ERIG”) chaired by Mr Bill Scales AO and including industry experts (Mr Geoff Carmody, Mr Alan Rattray and Mr David Swift) to develop detailed implementation arrangements for further energy market reforms.

ERIG must report back to COAG before the end of 2006 with proposed policy measures to:

- achieve a fully national transmission grid;
- address any structural issues affecting the competitiveness of the sector; and
- ensure that there are transparent and effective financial markets to support energy markets.

ERIG’s report will set out the case for or against further policy measures.

On July 2006 ERIG published an Issues Paper for public comment and received over forty submissions.

ERIG engaged KPMG to assist in formulating its views on the development of energy-related financial markets by examining three issues in further detail:

- the electricity trading market and any impediments to its development;
- the capital market and any impediments to investment in the energy sector; and
- the gas market and any impediments to its development.

This report addresses the first of these issues.

Appendix A summarises the terms of reference for this study.

2.1 Approach

In undertaking this study we:

- reviewed the ERIG Issues Paper and submissions;
- compiled and analysed quantitative and qualitative data on the operation of energy related financial markets in Australia and overseas;
- consulted with a limited panel of market participants to confirm market development issues and potential reforms; and
- concluded on the implications of this analysis for market development and proposed recommendations on possible areas of inquiry or policy reform.

2.2 Outline of report

This report provides the output of our analysis. In particular:

- Section 3 summarises market developments affecting the NEM since 2002
- Section 4 assesses the state of energy-related financial markets in Australia
- Section 5 outlines trading in environmental markets and market development issues
- Section 6 assesses issues in relation to promoting inter-regional trade
- Section 7 examines the trend towards vertical and horizontal integration in the NEM and its implications for financial markets
- Section 8 discusses the impact of government intervention in the NEM on development of financial markets
- Section 9 examines credit risk in the NEM and contracting market and opportunities to improve the efficient use of credit capital and reduce settlement risks
- Section 10 examines the issues affecting the utilisation of demand side management in energy risk management within the NEM

There are four appendices:

- Appendix A summarises our Terms of Reference
- Appendix B provides supplementary analysis on emission and renewable energy schemes in Australia
- Appendix C provides supplementary analysis on inter-regional trade and the Settlement Residue Auction process
- Appendix D provides supplementary analysis on demand side management.

2.3 Disclaimer

Inherent Limitations

This report has been prepared as outlined in this section 2 and Appendix A. The procedures carried out in preparation of this report constitute neither an audit nor a comprehensive review of the operations of energy related financial markets in Australia.

No warranty of completeness, accuracy or reliability is given in relation to the statements and representations made by, and the information and documentation provided by the officers of the Department of Industry Tourism and Resources (“DITR”) providing a Secretariat Service to the ERIG, who were consulted as part of the process.

KPMG has indicated within this report the sources of the information provided. We have not sought to independently verify those sources unless otherwise noted within the report.

In the course of our work, projections have been prepared on the basis of assumptions and methodology described in this report. It is possible that some of the assumptions underlying our projections may not materialise. Nevertheless, we have applied our professional judgement in making these assumptions, such that they constitute an understandable basis for estimates and projections. Beyond this, to the extent that certain assumptions do not materialise, it must be appreciated that our estimates and projections of results will vary.

KPMG is under no obligation in any circumstance to update this report, in either oral or written form, for events occurring after the report has been issued in final form.

The findings in this report have been formed on the above basis.

Third Party Reliance

This report is solely for the purpose set out in section 2 and for DITR which includes the use of this information in ERIG’s on going consultation process. The draft report is not to be used for any other purpose or distributed to any other party without KPMG’s prior written consent.

This report has been prepared at the request of the DITR in accordance with the terms of KPMG’s contract dated 13 July 2006, proposal dated 8 September and the Form of Order dated 11 October 2006. Other than our responsibility to DITR, neither KPMG nor any member or employee of KPMG undertakes responsibility arising in any way from reliance placed by a third party on this report. Any reliance placed is that party’s sole responsibility.

3 Market developments affecting the NEM since 2002

3.1 Findings of the Parer Review

The Council of Australian Governments' Independent Review of Energy Market Directions ("Parer Review"⁴) assessed the energy related financial markets as "quite illiquid" with:

- contracting restricted to sections of the forward electricity price curve ("forward curve");
- trading dominated by generators and retailers under bilateral arrangements to manage cash flow risks with few intermediaries to create liquidity;
- limited price transparency and relatively higher transaction costs affecting the cost of hedging exposures evidenced by relatively wide bid-offer spreads in the forward market; and
- the lack of a short-term market to balance hedge positions with load risks providing the incentive for enabling energy retailers to build or control the despatch of peaking capacity.

Illiquidity in financial markets was attributed at that time to:

- financial arrangements between state-owned energy businesses such as the Electricity Tariff Equalisation Fund ("ETEF") in NSW and the Benchmark Pricing Arrangement ("BPA") in Queensland⁵ to manage exposure to price risks reducing liquidity in the contracting market and raising the barrier for new entrant merchant generators and energy retailers in those states;
- a lack of transmission capacity and firm financial transmission rights ("FTR") that impeded inter-regional trade in contracting large capacity across state borders; and
- the existence of generator market power contributing to price spikes that increased the financial incentive for retailers to hedge their load risks and ultimately invest in generation portfolios.

3.2 Parer Recommendations

The Parer report recommended:

- *electricity financial market development*
 - The ETEF and BPA arrangements should be abolished irrespective of whether retail price caps are removed.

⁴ COAG, 2002 *Towards a Truly National and Efficient Energy Market*, Council of Australian Governments' Energy Market Review. Final Report, December 2002

⁵ Replaced by the Long-term Energy Procurement Scheme ("LEP")

- The National Electricity Rules should reflect the principle that the impact of any changes to the Rules must take into account the likely impact on financial market activity.
- Future reviews of the level of VoLL⁶ should take full account of the impact on contract premiums, contract availability and access to prudential cover.
- NEMMCO should review in 1 to 2 years the need to take an active role to facilitate the introduction of a voluntary clearing service for bilateral contracts.
- Demand side management

The NEM mechanism should be amended to include a demand reduction bidding option that would enable load reduction to be bid into the NEM for dispatch and payment in competition with generation offered into the market to meet demand. This would involve:

- users (including retailers and aggregators) bidding price and volume into the NEM to *reduce* load on a similar basis to generators;
- the NEM systems ‘stacking’ the demand reduction bids and the generator offers;
- the price of the demand bids being compared with the price of the generation offers, and the best combination selected to meet the demand; and
- accepted demand reduction bids being paid for their dispatch on an ‘as bid’ basis while generators would continue to be paid according to the system marginal price.

Installation of interval meters should be mandated for all consumers with the installation program to be achieved over the next 5 to 10 years.

3.3 Market developments since 2002

Key changes and market events since 2002 affecting energy-related financial markets referred to in this report include:

- commissioning of Bass Link and Tasmania joining the NEM in 2005;
- establishment of the Wholesale Electricity Market (“WEM”) in the south west of Western Australia (referred to as South West Interconnected System “SWIS”) from September 2006;
- announcement of the sale of ENERGEX and Ergon Energy retail businesses by the Queensland state government in 2006 and the consequential eventual removal of the LEP financial arrangements between state owned generators and retailers to hedge retail price capped loads; and
- the announcement by the NSW Government of the staged phase-out of ETEF by June 2010.

⁶ Value of Lost Load which is the maximum price to be set for electricity in the spot market, current set at \$10,000/ MWh

4 Energy related financial markets in Australia

4.1 Overview

Findings

- Market participants and intermediaries in the National Electricity Market (“NEM”) have three avenues to transact:
 - electricity futures and option contracts traded on the Sydney Futures Exchange (“SFE”);
 - over-the-counter (“OTC”) trades intermediated by brokers; and
 - bilateral trades directly negotiated between counterparties.

The broker-intermediated segment of the market typically facilitates transactions in derivatives to hedge shorter-term cash flow risks. Structured products including longer dated cap and load shaping products are negotiated as bilateral contracts between generators and retailers.

- Financial market trading continues to develop depth with positive implications for building liquidity and improving price transparency. However:
 - trading largely remains an asset-based market between merchant generators⁷, increasingly vertically integrated energy retailers and larger customers due to the minimal but expanding presence of financial intermediaries and non-asset-backed participants operating in the derivative markets; and
 - liquidity is concentrated at the short-end of the forward electricity price curve (“forward curve”) out to three years. This period corresponds to active trading in electricity futures contracts and broker intermediated contracting in the over-the-counter market.

As noted in section 7 of this study, electricity generators and retailers dominate trading in over-the-counter (“OTC”) derivative markets, by contracting with each other to hedge their exposure to spot price volatility on their sales and purchases of energy.

⁷ Defined as generators with no interest in retailing businesses

- Improving liquidity and price discovery is characterised by:
 - re-launch of SFE futures contracts in 2002 leading to a dramatic increase in trading volumes to date;
 - the emergence of new energy retailers in the NEM using the financial markets to manage electricity price and load risks further contributing to liquidity; and
 - the expanded role of brokers and participation of a broader range of financial institutions and integrated and global energy businesses in trading activity.

Limited price transparency in the bilateral contract market remains an issue as data on trades including pricing details negotiated directly between generators and retailers is not disclosed to the market.⁸

- While this market-wide development is encouraging and reflects the natural dynamics of market-based solutions, liquidity is not uniform and still broadly confined to segments of the forward curve out to three years, certain NEM regions and trading in vanilla base-load products. Lack of liquidity is particularly evident in:
 - South Australia; and
 - cap and structured flexing products.

The NEM also exhibits a tendency to be regionalised due to poor performance and generator bidding practices.

- Liquidity in the very short-term (e.g. day and week ahead) market is quite low evidenced by sporadic broker quotes and when available, large spreads. The introduction of a facilitated short-term market as recommended by a few submissions to ERIG conceptually has merit but market consensus is that this is unlikely to be successful within the NEM for contract confidentiality reasons as well as being viewed as additional interference in a developing market.
- Energy retailers continue to invest in building or controlling peaking capacity to manage demand-induced price spikes as an alternate solution to financial products – this is not necessarily a failure of the short-term contracting market but indicative of broader cost of capital and integrated business strategies. Conversely, merchant generators are supporting the establishment of new retailing ventures further evidencing the trend towards vertical integration in the NEM.

⁸ The Annual Financial Markets Report compiled by the Australian Financial Markets Association provides statistics on market turnover and outstandings in OTC and exchange traded electricity derivatives. Data on trade pricing is limited to exchange traded and broker intermediated segments of the derivative markets.

- The removal of ETEF will progressively add depth and significant liquidity in the NSW regional pool and more broadly across the NEM through inter-regional trading as generators and retailers substitute ETEF for bilateral arrangements. In the case of Queensland, the removal of LEP is more immediate in its impact on the contracting market following the state government's decision to sell its retailing businesses. Importantly, the sale will have implications for credit risk management practices and the assessment and pricing of credit default risk in the contract market as state-owned merchant generators are increasingly exposed to non-government rated, vertically integrated energy groups.

Recommendations

Financial markets are evolving in line with the maturity of the NEM and, in our view, will continue to do so without the need for further government intervention or policy reform.

4.2 Background

This study defines the 'energy-related financial markets' as comprising spot trading and the non-deliverable OTC and exchange-traded forward markets in electricity and gas.

Due to the emerging nature of the wholesale gas market and recent establishment of the wholesale electricity market in the south west of Western Australia, this report focuses principally on the development of derivative markets associated with trading in the NEM.

The NEM commenced operation in December 1998 as the wholesale spot market for electricity supply in the Australian Capital Territory and the states of Queensland, New South Wales, Victoria and South Australia. It comprises regions based on the state boundaries, with the Snowy Hydro Scheme being classified as a region in its own right. Tasmania became the sixth region of the NEM in 2005.

The NEM is a gross pool market design where the output from all generators is aggregated and scheduled to meet demand. In contrast, the wholesale electricity market in Western Australia follows the current UK market based on a balancing or net pool market design.

Financial arrangements to fix the wholesale spot price of energy between market participants in the NEM are typically transacted as contracts for differences ("CFD") or derivative financial instruments. Some transactions are structured as power purchase arrangements ("PPAs") or physical contracts.

Derivative financial instruments are subject to the accounting requirements of AASB 139 *Financial Instruments: Recognition and Measurement*. Section 4.9 in this report deals with some of the key implications of AASB 139 on the reporting of risk management activities and financial arrangements of market participants, and more broadly the energy-related financial markets.

4.3 Why electricity markets are different to other commodity markets

Electricity markets share many of the features of well-developed commodity and securities markets but there are also some unique characteristics of the operation of the wholesale spot market that have implications for financial trading in energy related financial products.

Wholesale trading in electricity between electricity generators and consumers of electricity in the NEM is conducted through a pool where the output from generators is aggregated and scheduled to meet demand. The pool is a set of rules and procedures that NEMMCO manages in conjunction with market participants and regulatory agencies. These market rules are set out in the National Electricity Rules.

Importantly for financial markets trading, electricity cannot be stored. Supply and demand must be balanced in real-time through a centrally coordinated dispatch process managed by NEMMCO as the market operator with the spot price representing the market clearing price.

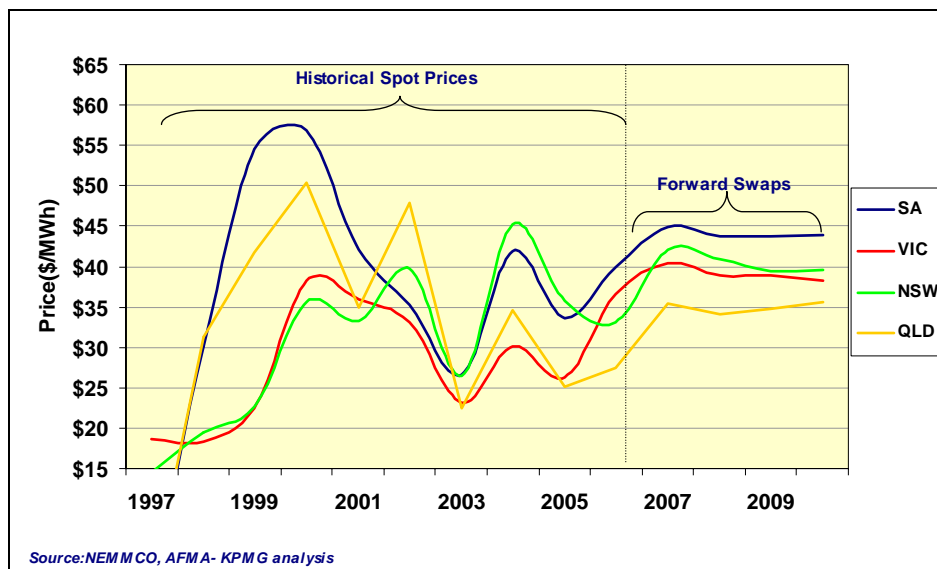
Market participants are dependent on the efficient operation of the transmission network and, in the case of energy retailers and large customers, the behaviour of generators in bidding capacity to supply energy. Both factors can degrade the system reliability in the day-ahead market and lead to price spikes without corresponding peak demand.

4.4 Wholesale electricity prices in the NEM

4.4.1 Spot and forward prices

The NEM, like other electricity markets exhibits significant volatility in spot prices due to the impact of transmission constraints, weather induced demand spikes and, potentially, generator bidding patterns. Figure 1 compares the relativity between the historical annualised flat spot prices by region and prevailing forward curves in the contracting market.

Figure 1
 Electricity Price Curves (\$/MWh) in the NEM – Cal Year Spot and Forward Prices (AFMA)



Spot prices have varied significantly between regions over time due to a number of factors including interconnection improvements, contracting levels and contestability roll-out, improved supply etc. In particular, the NEM has had to cope with relatively weak interconnections that have created a strong regional focus to the market. In particular:

- regional pool prices:
 - exhibit evidence of extreme volatility – often interpreted as an indicator of generator market power due to the small number of price spikes occurring each year and not necessarily at the time of constraints or peak load (refer section 4.5);
 - are converging although the differential between the highest and lowest regional pool prices (SA and QLD) has remained static in recent years after initially converging across the NEM;
 - often separate between regions at high price levels due to poor interconnection performance (discussed in section 6 on interregional trading); and

- are now trending upward thereby providing signals for further investment in generation.
- historical spot prices are not a good basis for predictor of forward contract prices.

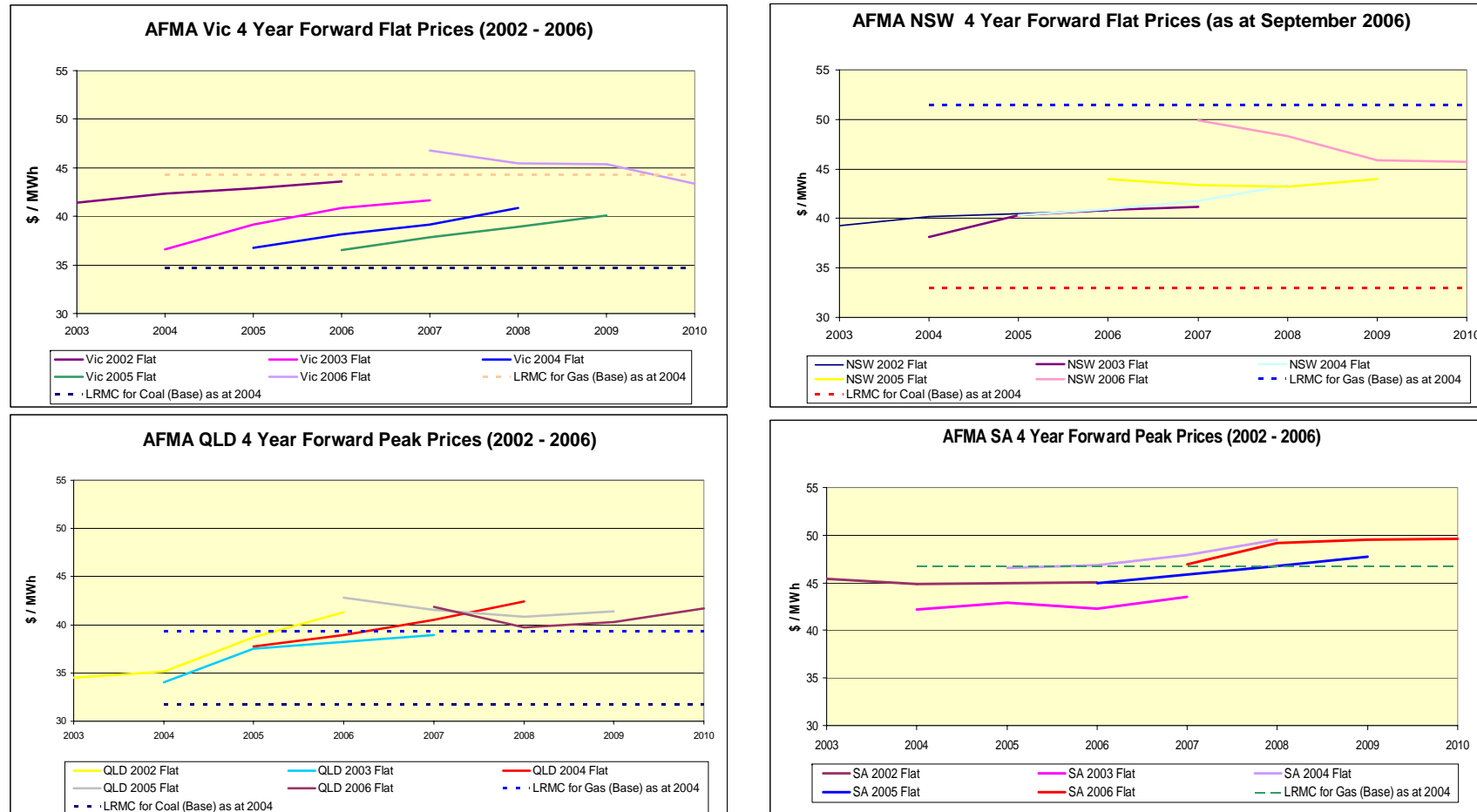
In combination, this volatility and the frequency of extreme price spikes acerbated by setting of the Value of Lost Load (“VoLL”) at \$10,000/ MWh provide financial incentives for market participants purchasing energy in the NEM to fully hedge their load requirements in the shorter term using swaps and cap products.

Figure 2 on the following page compares the AFMA forward curves⁹ to estimated long run marginal costs (“LRMC”) sourced from a number of recent studies in four of the NEM regions.

In broad terms, the analysis indicates that the forward curves in certain regions are converging with LRMC providing the necessary price signals for investment. While traded swap curves in the futures market and broker intermediated contracting markets are relatively short-dated compared to the time horizon for decisions to invest in long-life plant, they do provide a useful window to supply – demand imbalances in the NEM.

⁹ The AFMA Forward Electricity Price curve is a reference curve based on a survey of brokers. As a non-traded curve it may not reflect the forward prices that participants are able to contract in the forward market or buy and sell futures contracts on the SFE / d-cyphaTrade.

Figure 2
Comparison of Forward Curves to Estimated Long Run Marginal Costs



Source: AFMA
 Report on NEM Generator Costs (Part 2), Feb 2005, Acil Tasman

4.5 Price volatility in the NEM

Electricity markets including the NEM exhibit price volatility with short periods of extreme price spikes related to the characteristics of electricity outlined in section 4.3. While Figure 1 suggests the NEM in relative terms is less volatile than prior to market start this observation ignores the frequency and impact of price spikes that can expose market participants and energy retailers and financial traders in particular to material financial losses if unhedged.

This exposure is an inherent business risk and provides the incentive for market participants to substantially hedge their load risk with electricity swap and purchased cap products or invest in peaking generation to manage event risks and price spikes.

Figures 3-5 on the following page compares the distribution of spot prices in the NEM and NSW and VIC in particular since 2004. While the frequency of price spike over \$500 MWh has marginally declined, the financial impact has increased due to the increase in VoLL from \$5,000/MWh to \$10,000/MWh in 2002.

Table 1 further analyses relative change in the annual distribution of spot prices above \$500 MWh between 2002 and 2006. There are 17,520 trading intervals per annum¹⁰. While the frequency of price spikes increased marginally between 2002 and 2006 they have a significant impact on the average spot price for the year.

**Table 1
Attribution of Price Spikes to Annual Spot Revenue: 2002 and 2006**

MWh	2002 #	2002 %	2006 #	2006 %
500 – 10,000	314	21.6	128	18.1
5,000 – 7,000	10	1.7	9	3.1
7,000 – 10,000	3	0.7	10	4.4

A number of submissions and studies have observed that the level of price spikes appears to be caused by the bidding behaviour of generators unrelated to plant capacity constraints or unplanned outages as an issue. While the purpose of the study is not intended to analyse bidding practices in the NEM, the analysis does demonstrate that it only requires a few events within a trading interval for prices to rise to VoLL or close to it, so raising the average pool price for a calendar year by a significant amount.

¹⁰ Prices are published in half-hourly intervals i.e. 365days x 24hours x 2 = 17,520 half hours p.a.

Figure 3
Frequency of NEM Spot Pool Prices > \$500/MWh -all Regions

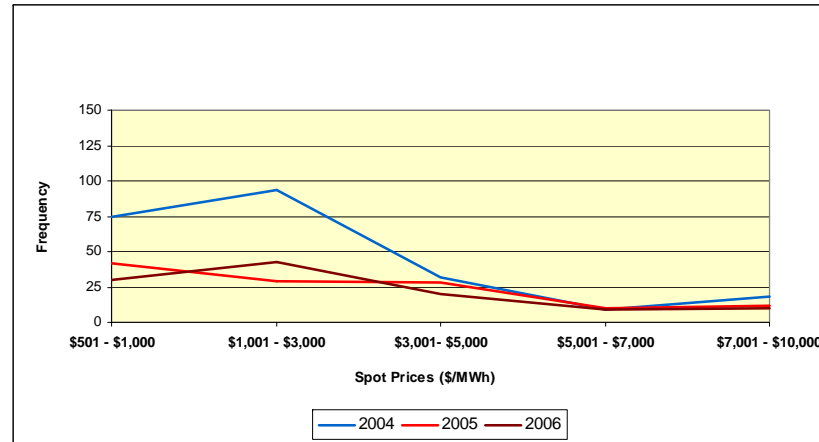


Figure 4 - NSW
Frequency of NEM Spot Pool Prices > \$500/MWh -all Regions

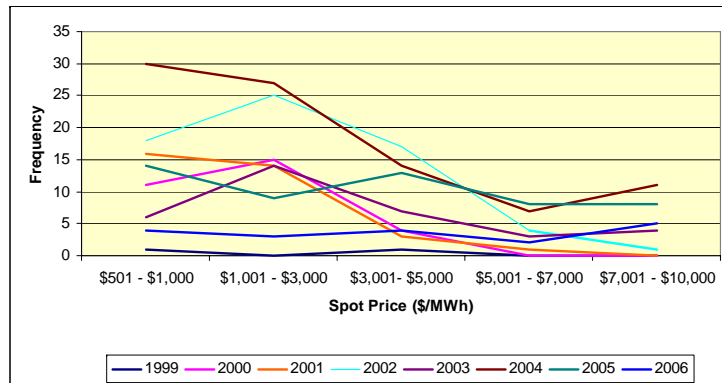
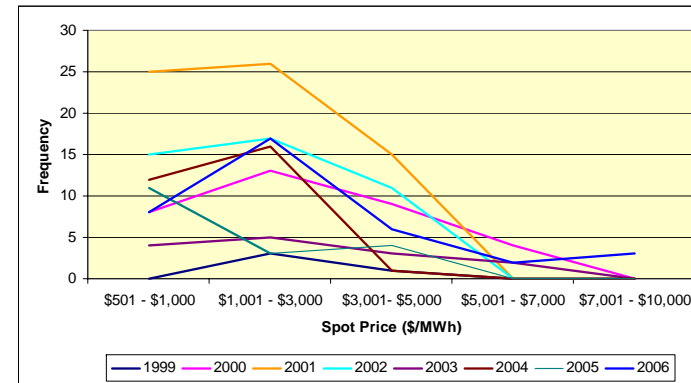


Figure 5 - VIC
Frequency of NEM Spot Pool Prices > \$500/MWh -all Regions



Source: NEMReview, KPMG Analysis

In response to these price spikes, energy retailers have typically established trading policies that fully hedge their highly probable forecast loads for the next twelve months and purchase additional insurance cover in the form of electricity cap products to cover weather induced demand and price spikes. The cost of hedging this risk increases the effective 'wholesale spot price' paid by retailers and major customers.

The lack of supply of these products, particularly in SA, does increase impact on the ability of participants to hedge their requirements at a reasonable cost and is providing the financial incentive for energy retailers to build and control the despatch of peaking generation assets as an alternative to contracting in the financial markets.

The liquidity of the electricity derivative market is analysed in Section 4.6.

4.6 Are electricity markets liquid?

4.6.1 Defining market liquidity

The essential characteristic of a *liquid market* is the existence of “*ready and willing buyers and sellers at all times*”. A market is considered *deeply liquid* if there are ready and willing buyers and sellers in large quantities where orders involving marketable parcels do not strongly influence prices.

In energy markets, liquidity in the contracting market serves two purposes: it produce reliable price signals essential to the development of futures and over-the-counter (OTC) derivative markets and the ability for market participants to hedge their cash flow risks without owning generation portfolios.

For the purpose of this study, we have adopted the following benchmark to assess market liquidity: *participants are able to transact a standard order within a reasonable timeframe to manage incremental load and price risks using reliable quoted prices that are resilient to large orders and have enough participants trading and sufficient volume to ensure low transaction and hedging costs.*

4.6.2 Assessment

Liquidity invariably takes time to build in emerging financial markets. The Australian experience in relation to the NEM illustrates this observation.

The forward markets in Australia have continued to evolve in recent years evidenced by:

- the presence of financial intermediaries operating in the Settlement Residue Auction process and trading off contractual positions;
- healthy growth in turnover in exchange traded and OTC derivatives trending in line with growth in NEM demand; and

- active futures and broker-intermediated markets.

While this market-wide development is encouraging and reflects the natural dynamics of market-based solutions, liquidity is not uniform and still broadly confined to segments of the forward curve out to three years, certain NEM regions and trading in vanilla base-load products.

Lack of liquidity is particularly evident in:

- SA following the sale of Southern Hydro; and
- cap and other peaking products.

The NEM also exhibits a tendency to be regionalised due to poor performance and generator bidding practices.

Financial hedging arrangements such as ETEF (NSW) and LEP (Queensland) exacerbate the issue of concentration of energy businesses owned by state governments with an adverse impact on liquidity in the contracting market.

We think vertical integration has had a marginal impact on the contracting market to date. Planned investment in generation assets together with merger and acquisition activity associated with the sale of state government owned energy businesses in Queensland and potentially in New South Wales may significantly increase the degree of vertical integration in the NEM leading to a more pronounced impact on market liquidity over time.

Structural factors contributing to illiquidity are broadly the result of government intervention (section 7), transmission operation and, to a much lesser degree, from merger and acquisition activity (section 8).

Price transparency remains an issue in the NEM. Impressive growth in the electricity futures market following the release of new contracts in 2002 has provided a valuable window for market participants generally and new entrants in particular to assess and price the cost of hedging exposures. However, the relatively wide bid-offer spreads on exchange traded and broker-intermediated trades¹¹ compared to traditional financial markets and limited access to price data on bilateral contracts restricts price discovery in the base-load market thereby making it difficult to evaluate the economic cost of structured financial hedges compared to investment in generation portfolios to manage. It is in this segment of the market that generator power if exercised is likely to have a significant effect on the risk premium for hedging the wholesale spot risk.

The removal of ETEF in NSW and sale of retailing assets in Queensland will be positive for the contracting market over time and contribute further liquidity as merchant generators and retailers re-contract across the forward curve.

¹¹ *Independent Survey of Contract Market Liquidity in the National Electricity Market* commissioned by the National Generators Forum and Energy Retailers Association of Australia, October 2006 (“NGF/ ESAA Survey”)

We expect price transparency to continue to improve with increasing liquidity in the futures market for longer dated contracts to match participants' medium term hedging horizons. The bilateral contracts market which provides hedge cover for longer-term portfolio risks is and will remain less transparent. This is no different to the experience in other commodity markets.

A number of submissions have raised the issue of migration to full nodal pricing to address transmission operation issues. While transmission planning and operation is outside the scope of this study, we note in passing that full nodal pricing is likely to have a negative effect on financial market liquidity by diffusing regional liquidity to an intra-regional level increasing basis risk for retailers and ultimately the cost of hedging. A study of the New Zealand Electricity Market in 2002 found that full nodal combined with specific features of the NZEM did have a negative impact on liquidity in that market¹².

4.7 Analysis of trading in electricity derivatives

This section analyses turnover and liquidity in the exchange traded and forward contracting segments of the electricity derivative market.

4.7.1 Market turnover

4.7.1.1 Market and regional liquidity

There is no centralised reporting of statistics on turnover in the energy related derivatives markets. For the purpose of this study, reference has been made to the annual statistical survey of Australia's financial markets conducted by the Australian Financial Markets Association¹³ and statistical data provided by SFE/ d-cypha. Data on broker intermediated trades was not available at the time of compilation of this report.

The analysis indicates that market turnover has broadly developed in line with annual system demand over the period 2000-2005. Statistics for 2006 are not currently available although anecdotal evidence indicates liquidity continues to improve. We note however concerns raised in submissions on the impact vertical integration on market liquidity is yet to be observed in statistics on market turnover and contracting capacity for the reasons noted in section 4.6.2.

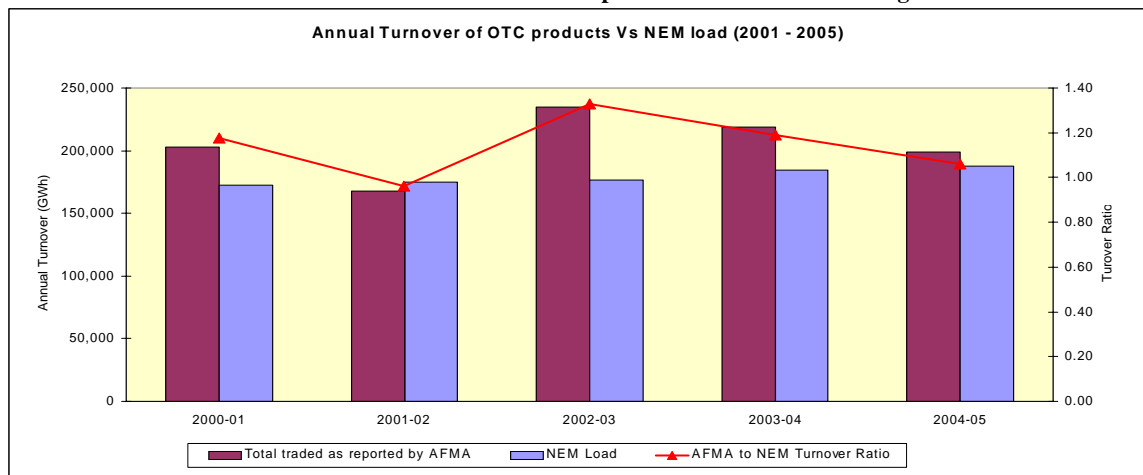
More than half the trades transacted involve brokers¹⁴ highlighting the important role of intermediaries in the contracting market and their contribution to price transparency.

¹² The New Zealand Electricity Market ("NZEM") operates a full nodal pricing ("FNP") regime. The NZEM Rules Committee commissioned a review of the outcomes of FNP regime in 2002. The study concluded "*FNP contributes to the lack of liquidity in nodal forward markets. Lack of liquidity in the hedge markets is a significant obstacle to efficient risk management for many market participants and presents a barrier to investment by new entrant generators*". p 48 Assessment of Outcomes Achieved by Full Nodal Pricing in the NZEM, NZEM Rules Committee, 2002

¹³ The AFMA Australian Financial Markets Report is a survey of market participants' comprising OTC broker intermediated and bilateral trading activity

¹⁴ Refer Page 12, NGF/ESAA Survey

Figures 9
Annual Turnover of OTC Products compared to NEM Load – All Regions



Source: AFMA, NEMMCO

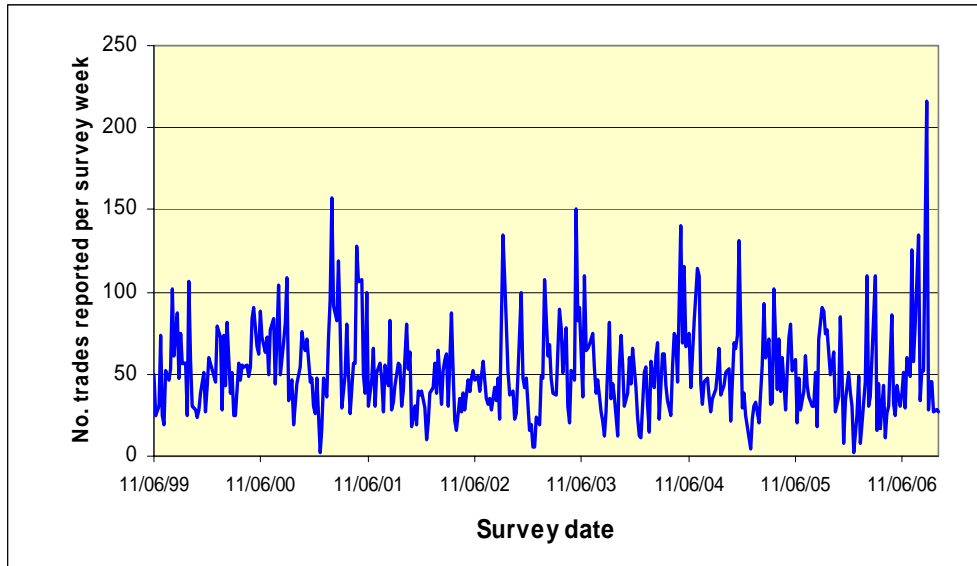
Figures 11-14 on the following pages compare turnover by region. In broad terms, the depth of liquidity varies across the NEM and segments of the contracting market. Specifically:

- liquidity is lower in SA than in other regions;
- contracting is largely intra-state which significantly reduces competition – lack of products to effectively hedge inter-regional risk is often cited as the main reason for this effect;
- the market for longer term structured products (load following swaps and volume flexing cap products) by its very nature has limited contracting capacity. The acquisition of Southern Hydro by AGL in 2005 is expected to reduce contracting capacity in the cap market as capacity is used to meet the group’s own hedging requirements; and
- changes in the ownership of generation assets leading to vertical integration with energy retailers post June 2005 may contributed to a perceived deterioration in structural liquidity by affecting the ability of existing counterparties to re-contract (refer Section 5.1.2).

The following data on trading activity is sourced from EnergyBankLink¹⁵. Whilst reported OTC activity has fluctuated significantly over time, there is evidence of increased trading activity in 2006 with a record 216 trade transacted in early September 2006.

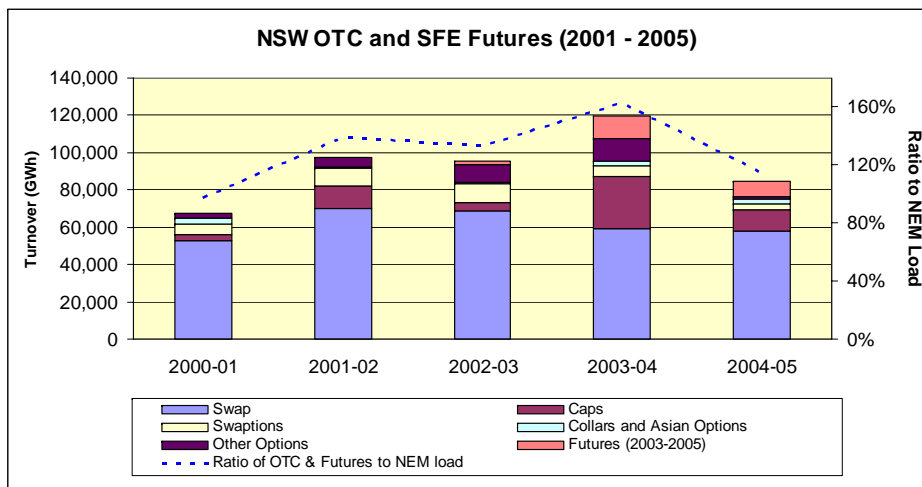
¹⁵ EnergyBankLink surveys 10 market participants at the close of each trading week and obtains data regarding OTC contract volumes dealt by those participants during that week. OTC contracts are aggregated for the purposes of reporting and may comprise *swaps, swaptions, options, interregionals, and any variation thereof that arises from time to time in the market*. The participants are surveyed from the generating, retailing and trading sectors of the market, and the parties are rotated as much as possible from week to week.

Figure 10
Shows number of OTC recorded by the EBL survey from June 99 to Oct 06

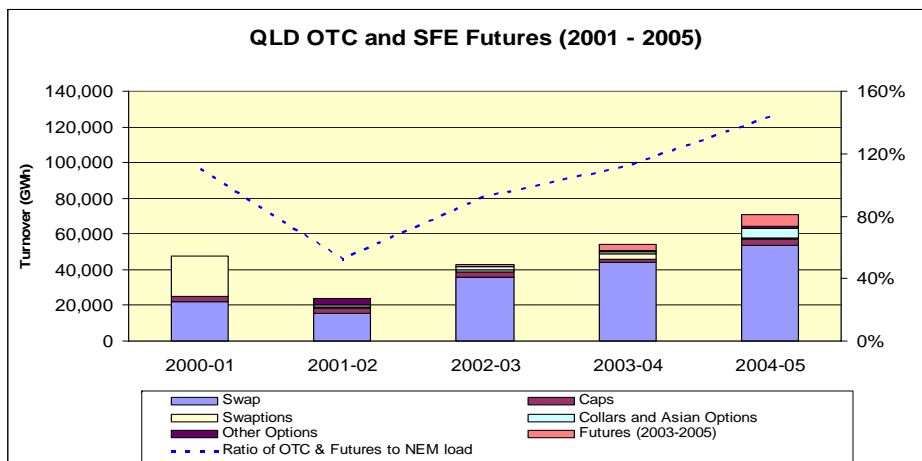
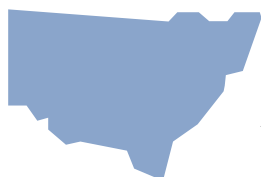


Source: EBL Survey 1999-2006

Figures 11-12
Traded Volumes in Futures and OTC Derivative Contracts: NSW and Queensland

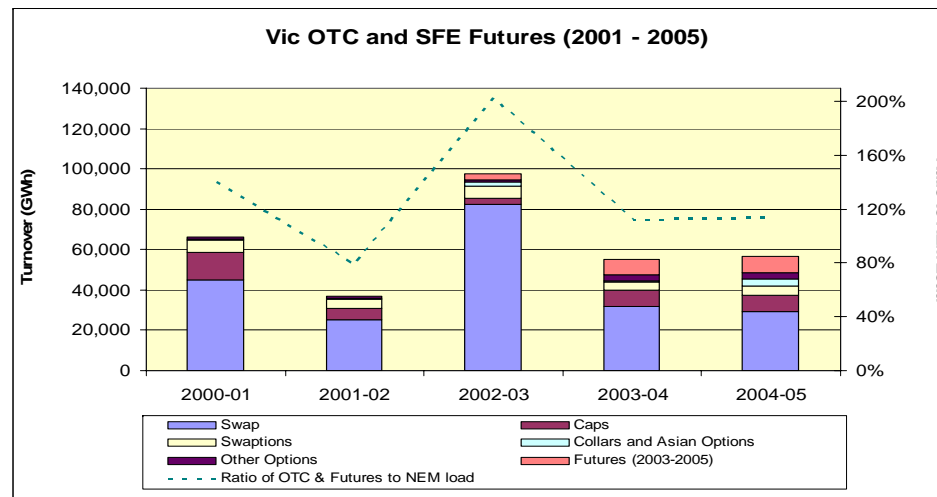


Source: AFMA, d-cypha and NEMMCO

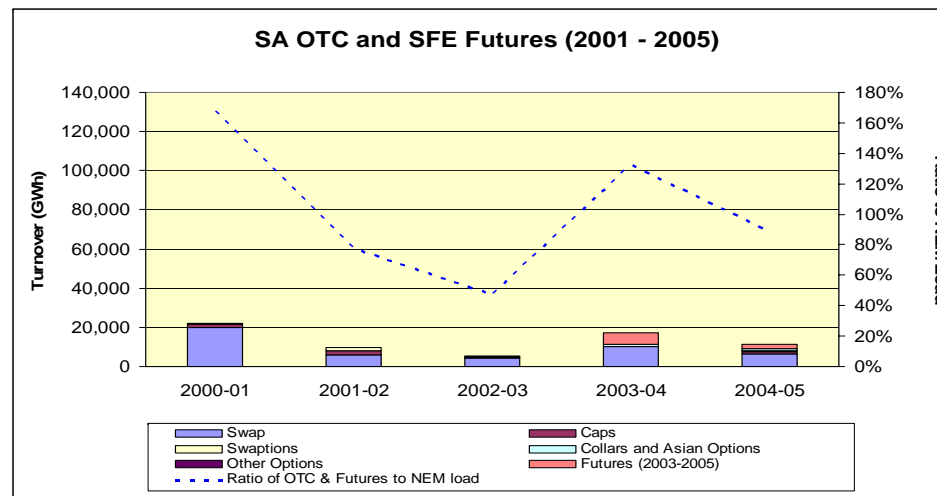
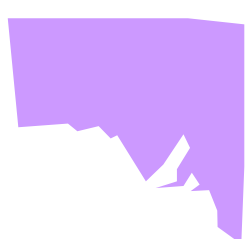


Source: AFMA, d-cypha and NEMMCO

Figures 13-14
Traded Volumes in Futures and OTC Derivative Contracts: Victoria and South Australia



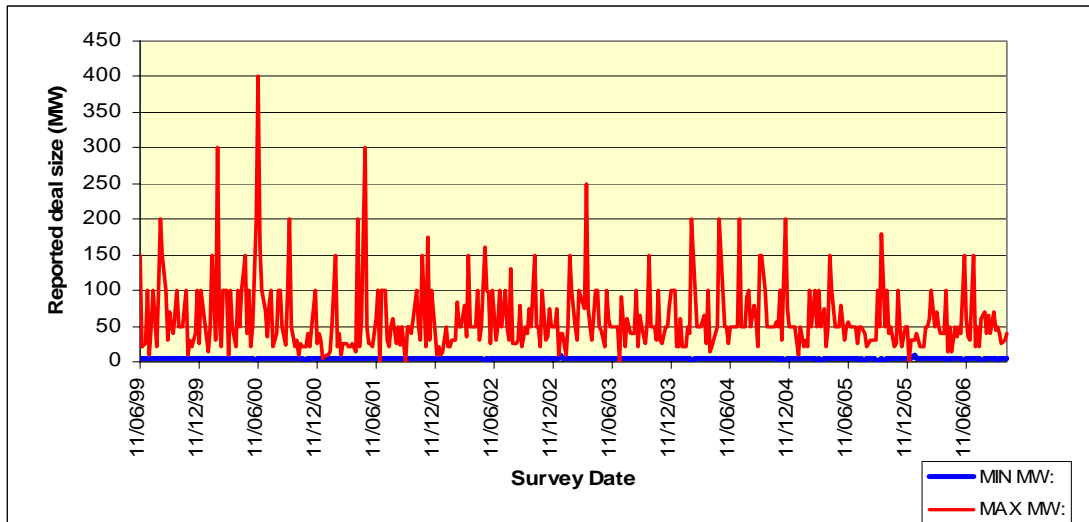
Source: AFMA, d-cypha and NEMMCO



Source: AFMA, d-cypha and NEMMCO

Figure 15 graphs the size of deals over the period 1999 to 2006.

Figure 15
Minimum and Maximum Deal Size Reported over the Period Jun 99 to Oct 06

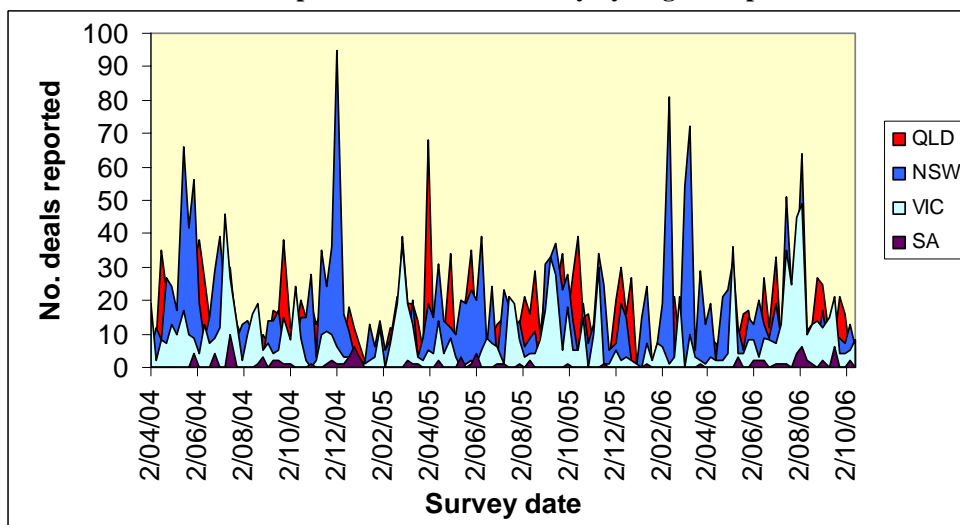


Source: Energy Bank Link, KPMG Analysis

The analysis shows that size of report deals in outright MW terms appear to have trended down since the commencement of the survey. While the causal factors may not be clear it can also be viewed as an indication of increasing depth in the market enabling smaller contract sizes to be transacted in order to shape hedge portfolios to load risk.

Figure 16 analyses trading activity by region.

Figure 16
Number of Deals Reported in the EBL Survey by Region: Apr 04 to Oct 06



Source: Energy Bank Link, KPMG Analysis

The analysis highlights:

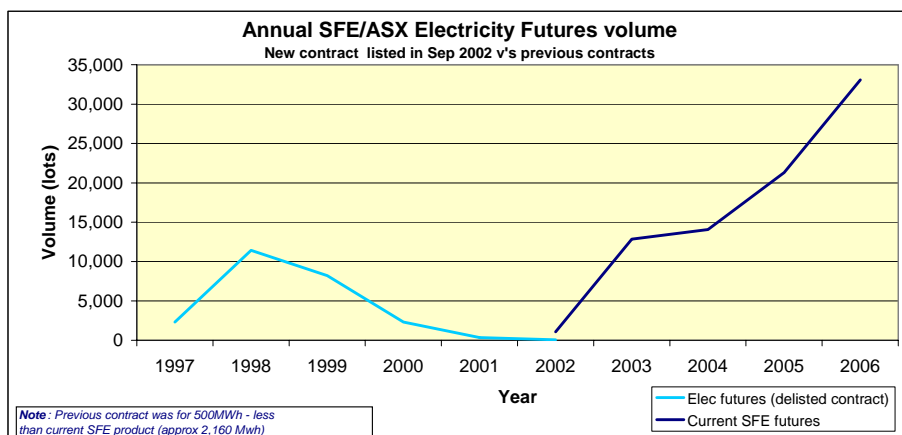
- NSW trading activity has fluctuated significantly over time but appears to have trended down in 2006; and
- SA trading activity remains very low, but appears to have increased slightly in 2006;
- VIC trading activity has increased substantially in 2006.

4.7.2 Exchange traded electricity contracts

4.7.2.1 Futures trading prior to 2002

NEM participants have been able to trade electricity futures since prior to market start. However, contracts traded prior to 2002 were based on 500 MWh unit which reduced their appeal as a risk management product to hedge short-term price risk given the lack of depth in the market to accommodate the volumes required to meaningfully hedge price risk.

Figure 17
Annual Trading Volume in Electricity Futures: 2002 – 2006



Source: SFE, KPMG Analysis

By 2002, volumes traded had declined to the point where the contracts were illiquid and ceased to be relevant as a reference point for price discovery and hedging portfolio risks.

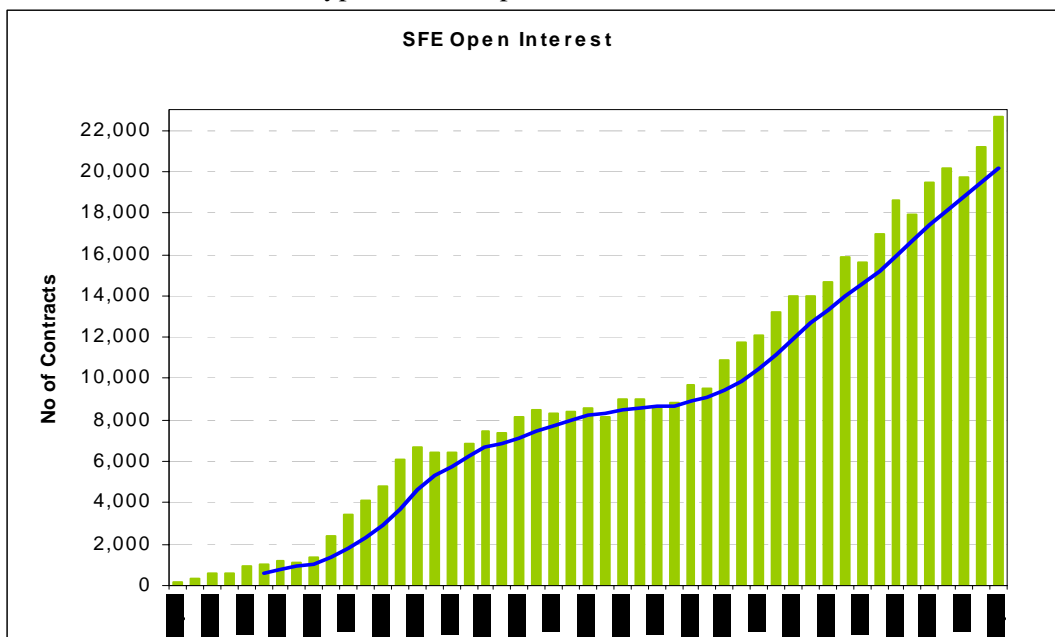
4.7.2.2 Re-launch of electricity contracts

SFE / d-cypha re-launched 8 futures products in September 2002 based on 1 MWh unit up to 15 quarters out. The new contracts addressed deficiencies with the old SFE contracts that contributed to their lack of appeal.

Since launch of the futures contracts, turnover has grown considerably to 54.6 TWh¹⁶, equivalent to 20 - 25 per cent of NEM demand and total market turnover in electricity derivatives with significant open interest positions. The involvement of financial intermediaries has promoted liquidity.

A significant contributor to this growth has been the use of the block trade facility¹⁷ to manage credit risk between contracting parties in the NEM reflecting the advantages of the futures market over OTC contracting practices. Market participants in the NEM are able to convert OTC positions from bilateral contracting into futures equivalent contracts transacted through the SFE to overcome restrictions on available credit limits to accommodate these trades. The announced sale of the Queensland government’s interests in its energy retailing businesses may have contributed to the increased use of block trades observed during 2006.

Figure 18
SFE/ d-cyphaTrade – Open Interest from 2002 - 2006



Source: D-Cypha

¹⁶ NGF/ ESAA Survey, page 13

¹⁷ The Block Trade Facility (BTF) operated by the Sydney Futures Exchange is an off-market trading mechanism enabling market users to arrange and transact orders of significant size in specified contracts.

The rejuvenated futures market has contributed to overall liquidity in the forward markets providing two important benefits to market participants:

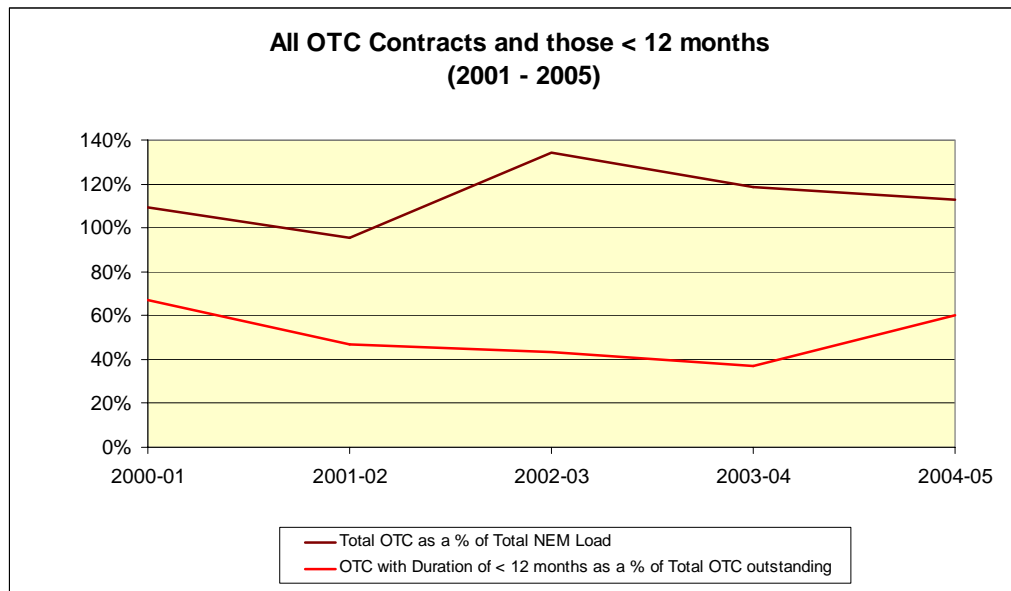
- newer retailers entering the NEM have cost effective and credit efficient risk management products to manage their load risks; and
- facilitates price discovery in assessing the hedging premium, a significant advantage to the non-traded AFMA forward electricity reference (swap) curves.

4.7.3 Trading risk horizon - maturity of contracting portfolios

Most energy retailers have hedging policies that require load to be fully-hedged on a rolling 12 months basis with the hedging benchmark percentages progressively reducing over a hedging horizon out to 5 years.

Figure 19 compares the OTC outstandings less than 12 months as reported in the AFMA survey to NEM load. Approximately 40 – 60 per cent of contracting portfolios as the 30 June survey date is hedging short-term cash flow exposures leaving the balance of exposures to be re-contracted during the year (or in certain cases covered by generation portfolios).

Figure 19
Comparison of OTC Contracts With Less Than 12 Months to Maturity to NEM Load and Total Outstandings



Source: AFMA, NEMMCO

The emphasis on short term hedging horizons is also evident in an analysis of SFE Futures Open Interest – 25th September 2006 (Figures 20 – 23 on the following page). Most of the open interest in futures contracts is concentrated in the near term periods with liquidity declining after Cal 07. Option volumes are building but remain considerably less liquid compared to the bilateral contracting market.

The availability of data for 2006 will provide an insight into the impact of vertical integration on market liquidity as it will cover the period immediately following major acquisitions of generation assets by integrated energy groups.

4.7.4 Price transparency

The futures market is increasingly important to the contracting market providing a transparent and anonymous medium for price discovery. However, the concentration of liquidity in near term base-load and strip contracts limits the usefulness of the futures market to meaningfully evaluate long term hedging costs associated with structured load-shaping products and portfolio decisions to invest in generation assets.

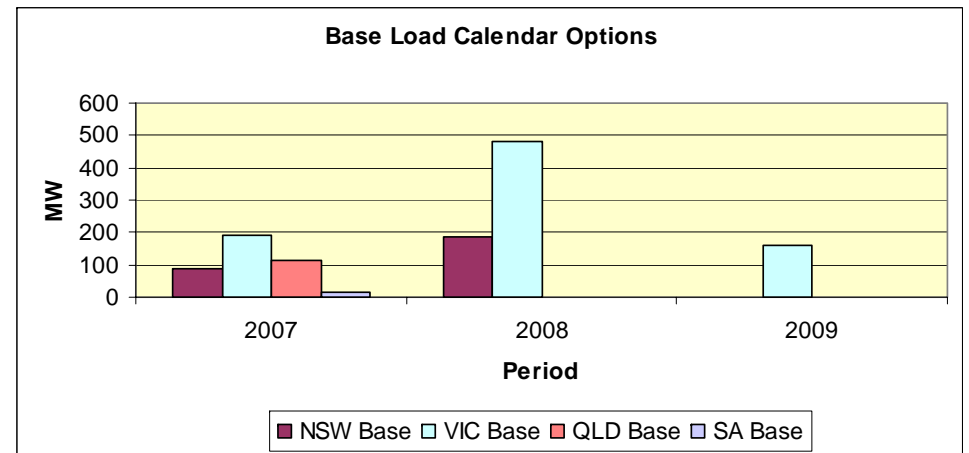
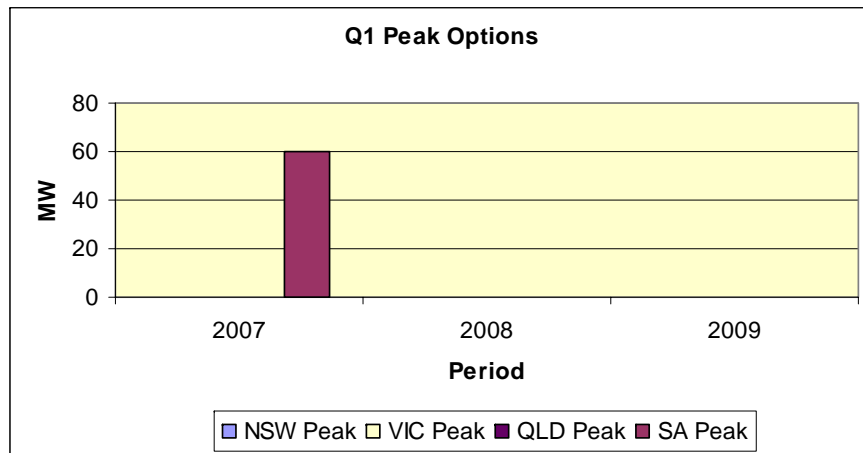
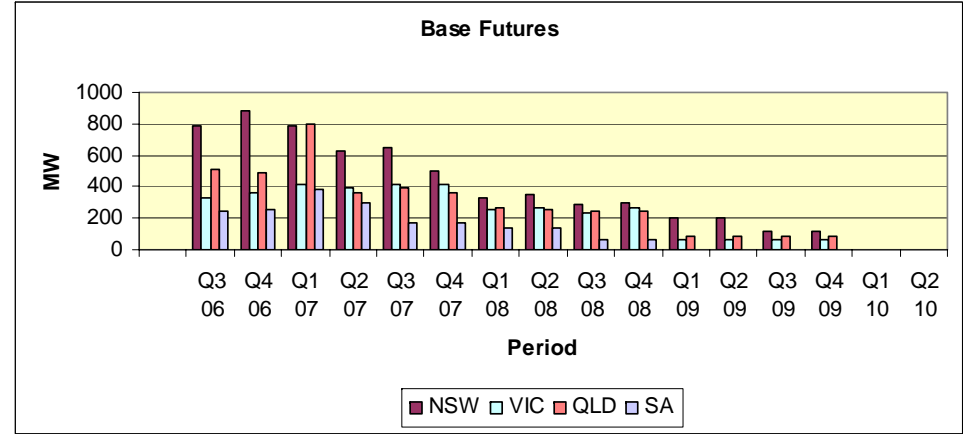
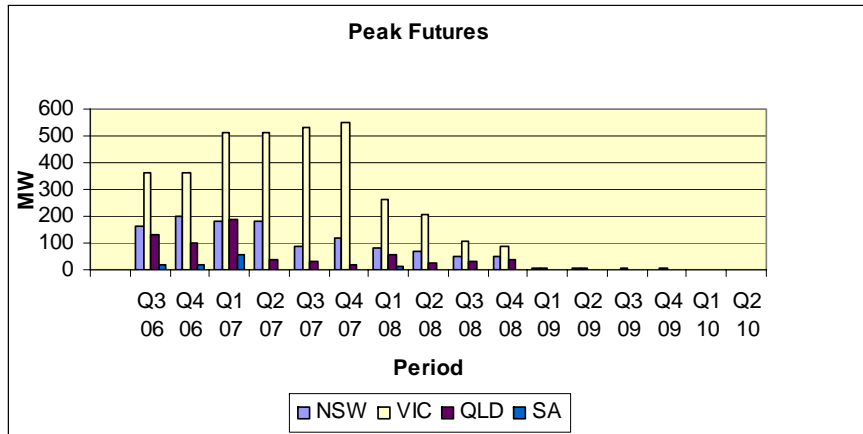
In this regard, the investment by AGL in Loy Yang A has provided the group with ‘a window into the base-load market’ to access trade volumes, prices and contracting levels¹⁸.

Larger participants are more able to justify the expense of collecting the best available information on market outcomes at the expense of smaller participants. While public release of price data may be desirable to improve price discovery across the entire forward curve this should be left to market forces to provide the incentive for disclosure.¹⁹

¹⁸ StandardandPoors RatingsDirect, - AGL August 2006

¹⁹ The Financial Services Authority responsible for regulating the financial services industry in the UK conducted a study on the transparency in the secondary bond market. The FSA concluded that participants in the UK's predominantly wholesale markets may find existing transparency levels deficient however the regulator would defer to the market in the first instance to generate solutions to these deficiencies rather than through regulation. *FS06/4: Trading Transparency in the UK Secondary Bond Markets - Feedback on DP05/5* Financial Services Authority

Figures 20-23
 Analysis of SFE/ d-cypha Futures Open Interest – 25th September 2006

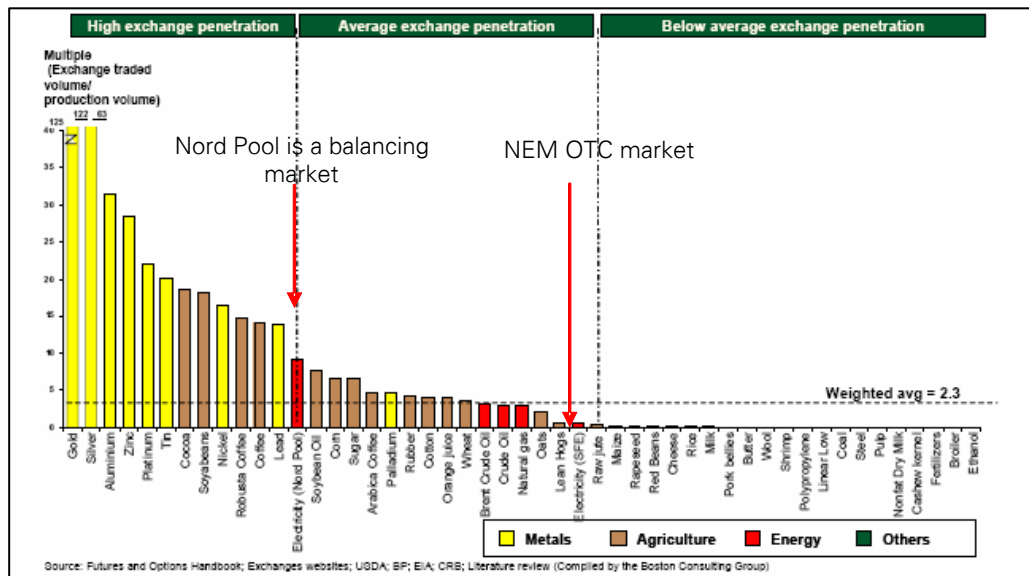


Source: D-Cypha

4.8 Comparison of NEM liquidity to energy and commodity markets

The unique characteristics of the design of electricity markets such as the NEM in particular make any direct comparison to the liquidity observed in international energy and commodity markets problematic. Notwithstanding, there are some useful observations.

Figure 24 has been compiled by the SFE/ d-cypha and included in their submission to ERIG.



SFE submission, KPMG analysis

Table 2 compares the characteristics of the NEM to reference energy markets.

Table 2
 Summary Data on Structure of Reference Energy Markets

	NEM	Nord Pool	UK	PJM
Market design	Gross pool	Net pool	Net pool	Net pool
System load	200TWh	400TWh	355TWh	728TWh
Market customers and participants	<100	300	200	400
Population	20M	24M	60M	51M
Liquidity assessment	Low very short-term Reasonable medium-term	High	Low since NETA – few forward trades	High out to 24 months

Figure 21 and Table 2 provide a useful context on the healthy development of liquidity in the NEM given the size of the market, its design, relative low number of market participants and the influence of government policy on the operation of the financial market.

The key observations are:

- The NEM is the only gross pool market in the reference group and one of few such markets globally (New Zealand is another gross pool market). In such markets OTC cash settled contracts would tend to mirror bilateral deliverable contracting in managing load related price risks.
- Comparisons between Nord Pool often used as reference market and the NEM need to take account of the differential loads traded through the spot markets. Adjusting for total market load does still confirm the greater depth of the market in the NordPool compared to NEM.
- The limited number of participants operating in the NEM impacts on the depth of the market. Government ownership and the impact of financial arrangements as well as vertical and horizontal integration further limits the number of active participants.
- Other energy and commodity markets are truly global in nature supported by single or multiple financial exchanges that promote liquidity in the futures markets which in turn support active forward markets.

4.9 Transition to A-IFRS and implications of AASB 139 to energy markets

4.9.1 Overview

AASB 139 relates to recognition and measurement of financial instruments and is part of the suite of standards that comprises Australian-equivalents to International Financial Reporting Standards which became effective four years commencing after 1st January 2004. Companies were given the option of deferring the adoption of AASB 139 by twelve months and so became effective from 1st January 2005.

For all practical purposes, most market participants reported for the first time under AASB 139 for the financial year ended 30th June 2006 although the impact of the standard on risk management practices, financial arrangements and bilateral contracting was evident as early as 2004. These impacts mainly related to the uncertainty of the accounting treatment of long-term derivative hedging transactions that mirrored the terms in deliverable contracts.

4.9.2 Observations

- AASB 139 requires, inter alia:
 - all financial derivatives to be recognised on the balance sheet and measured at fair value
 - changes in fair value are recognised in the profit and loss statement unless hedge accounting is adopted
 - any ineffectiveness in a hedge relationship is immediately recognised in the profit and loss statement
 - effective changes in fair value relating to cash flow hedges are initially reported in equity and recognised in the profit and loss statement at a later date together with reporting of underlying cash flows (same as old GAAP)
 - net written (sold) options do not qualify for hedge accounting and are immediately recognised and subsequently remeasured in the income statement at fair value
 - prescriptive rules for deriving fair values, measuring hedge effectiveness and separating embedded derivatives from physical contracts
- The gross pool design of the NEM means that all contract for differences (CFDs) to fix the price of electricity are automatically within the scope of AASB 139 as derivatives. AASB 139 has had a major impact on generators and retailers in Australia compared to participants on net pool markets since their contracts are prima facie deliverable contracts and outside the scope of the standard. International Financial Reporting Interpretations Committee (IFRIC) has not been sympathetic to requests to see through market design.
- Achieving hedge accounting within the prescriptive rules of AASB 139 has been a difficult process for the sector due to:
 - long term contracts containing physical constraint parameters and optionality which is problematic to value and creates issues in measuring hedge effectiveness
 - a lack of consensus on valuation methodologies for structured products
 - limited liquidity in electricity option markets to support use of traded prices as basis of valuation
 - lack of consensus on interpretation and implementation issues
- Some impacts on risk management activities are emerging in the following areas:
 - portfolio management and asset optimisation strategies of generators and retailers are difficult to accommodate under the transaction-orientated hedge designation requirements of the standard

- risk products used by retailers such as high price caps, are treated as trading instruments and do not usually qualify for hedge accounting
- caps sold by peaking generators which are basically covered, do not qualify as hedges for accounting purposes
- some physical gas supply contracts are treated as derivatives

In broad terms, AASB 139 does have a significant impact on market participants operating in the NEM with large contracting portfolios due to the prescriptive nature of the standard, challenges in accommodating the standard's transaction-based rules and complex data management requirements given the extensive use of portfolio management practices by energy risk managers and lack of consensus on generally accepted valuation practices for structured electricity derivatives. Limited price discovery in the bilateral and option segments of the forward market acerbates concern over the reliability of valuations.

At the margin, the standard is influencing the way market participants are managing their risks however anecdotal evidence suggests it is not providing a disincentive to hedge with this decision based on market participant's energy trading policies and cash flows at risk. Accordingly, there is no evidence that the adoption of a new accounting standard for financial instruments is impacting on market liquidity.

4.10 Recommendations

Recommendation

Financial markets are evolving in line with the maturity of the NEM and, in our view, will continue to do so without the need for further government intervention or policy reform.

5 Environmental markets

5.1 Overview

Findings

- Emissions and renewable energy schemes in Australia have managed to facilitate renewable energy project development to a reasonable level despite their lack of integration and uniformity. These schemes are primarily used by liable entities and emitters to comply with regulatory requirements rather than designed to encourage the underlying credits or certificates to be actively traded and priced in competitive financial market.
- Government hesitation in implementing a national emissions trading scheme has resulted in a number of fragmented, largely state-based schemes that encourage compliance-based transactions and generally do not promote active trading and speculation.
- Existing schemes have encouraged structured physical and physically related power projects that often provide bundled electricity supply and environmental products such as RECs and NGACs to the purchaser. These structures can be quite significant in size and yield a substantial number of environmental entitlements but are transacted bilaterally and hence are not typically transparent.
- The EU Emissions Trading Scheme (ETS) is a useful market from which comparisons and key lessons for the evolution of the Australian environmental markets can be drawn. Whilst there have been a few technical and operational issues that need to be address over time it is clear that this scheme has been successful in encouraging and facilitating emissions trading in Europe. The inter-relationship (and correlation) between carbon prices under the ETS and electricity and gas prices has created interesting cross-market dynamics and has also encouraged integrated trading/hedging across each of these. This is a key dynamic that is not as prevalent in Australia.

Recommendations

- The existing renewable energy schemes should be replaced by the adoption of a national emissions trading scheme that is capable of being implemented in a timely manner and integrated into a global scheme in the future. This issue has been examined as part of the accompanying report on Capital Markets and Investments which found a need for a consistent policy to price carbon emissions.

5.2 Emissions and renewable energy related schemes in Australia

There is emerging consensus that climate change is a significant threat to Australia's economy, population and environment. While development of an international emissions trading market has received considerable focus in recent times, the development of a national emissions trading scheme in Australia has been slow to translate into policy despite emerging consensus on the need to place a price on carbon emissions to promote a market-based solution.

A discussion paper released by the National Emissions Trading Taskforce in August 2006 sets out a possible design for a national emissions trading scheme and calls for public consultation through submission to the taskforce by the 22 December 2006. This is a positive development. Due to existing state-based emission and renewable energy schemes, strong federal government support will be essential before such a national scheme can be effectively implemented.

The existing emissions and renewable energy related schemes in Australia include:

- The federal Mandatory Renewable Energy Target (MRET) scheme enforced by the Renewable energy (Electricity) Act 2000- based on Renewable Energy Certificates (RECs);
- NSW Greenhouse Benchmark scheme- based on NSW Greenhouse Abatement Certificates (NGACs);
- QLD Gas scheme- based on Gas Electricity certificates (GECs); and
- The Victorian Renewable Energy Target (VRET) scheme- based on Victorian Renewable Energy Certificates (VRECs).

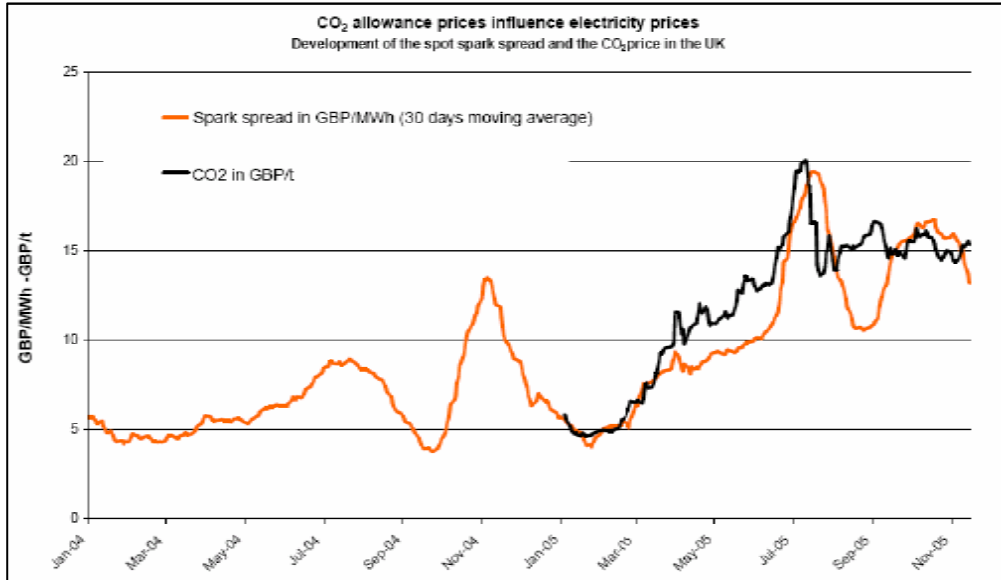
For further information in relation to these schemes see Appendix B.

5.3 The European Union (EU) Emissions Trading Scheme (ETS)

5.3.1 Impact on electricity prices

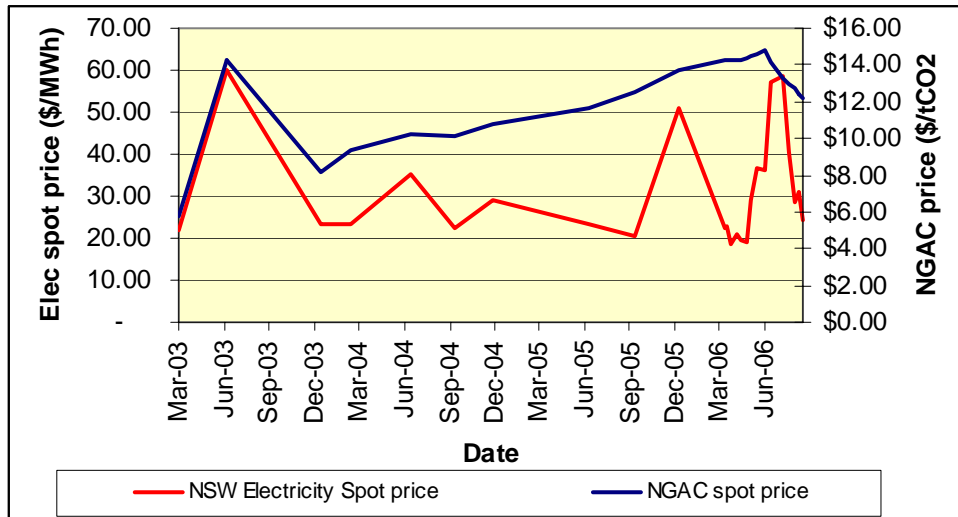
The EU ETS officially commenced on 1 January 2005. It is expected to set a strong precedent for domestic emissions trading schemes in Australia and globally. Figure 25 below shows key trends towards higher electricity prices during the first 12 months operations of the EU ETS.

Figure 25
 Spot spark spread and CO2 prices across Europe



Source: E3 International, Introducing Climate Change Policy and its Impact on Energy Businesses –An International Perspective, 2006.

Figure 26 NSW daily average spot prices against NGAC spot prices.



Source: NEMMCO, AFMA, KPMG Analysis

Note that like the EU ETS chart shown in figure 25 above, there is some degree of correlation between NGAC spot prices (akin to carbon) and NSW daily electricity prices for a number of data points selected within the period March 2003 and September 2006 but this is difficult to

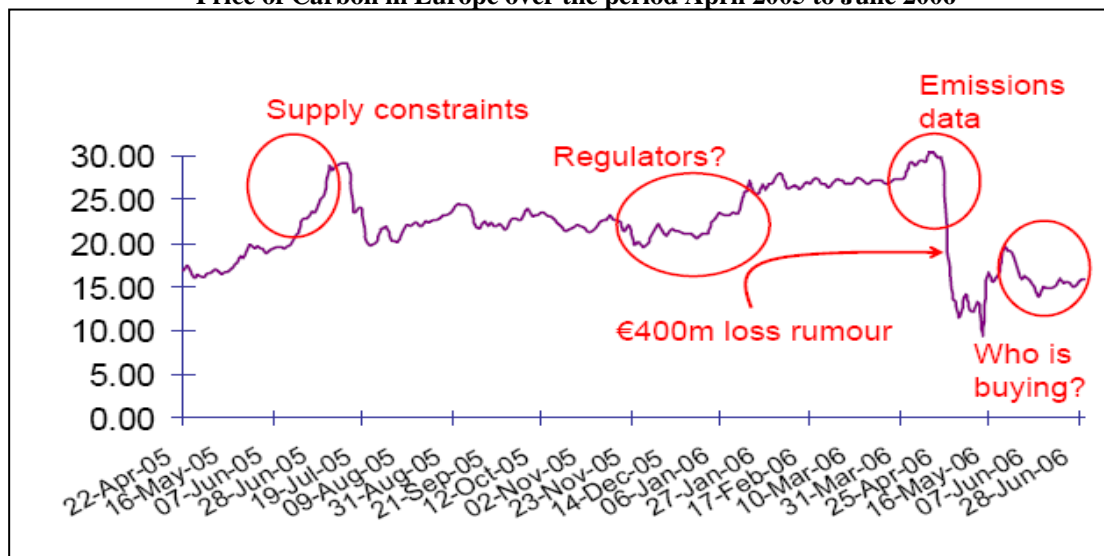
draw conclusions around given the relative small change in NGAC prices in comparison to spot prices.

5.3.2 Features and key trends

- The EU scheme is a Cap and Trade design with a geography covering 15 original EU Member States from 1 January 2005, and 10 Accession Countries from 2006 onwards
- There are significant penalties for non-compliance €40/tCO₂ shortfall in Phase 1 between 2005 and 2007, a -€100/tCO₂ shortfall in Phase 2 between 2008 and 2012
- Mandatory calculation and reporting of emissions with country specific methodology- broadly consistent across EU market
- Significant simplifications have been made in design of the EU ETS scheme including:
 - CO₂ only
 - no recognition of DSM
 - no recognition of carbon sequestration
 - no recognition of reduction in transport sector emissions

The price of carbon has trended down significantly in April 2006 following recognition that a number of countries emitted less than expected in 2005. This price trend is evident in the figure 27 below and is evidence that whilst challenges remain in relation to some aspects of market design, market forces are operating well with the EU ETS.

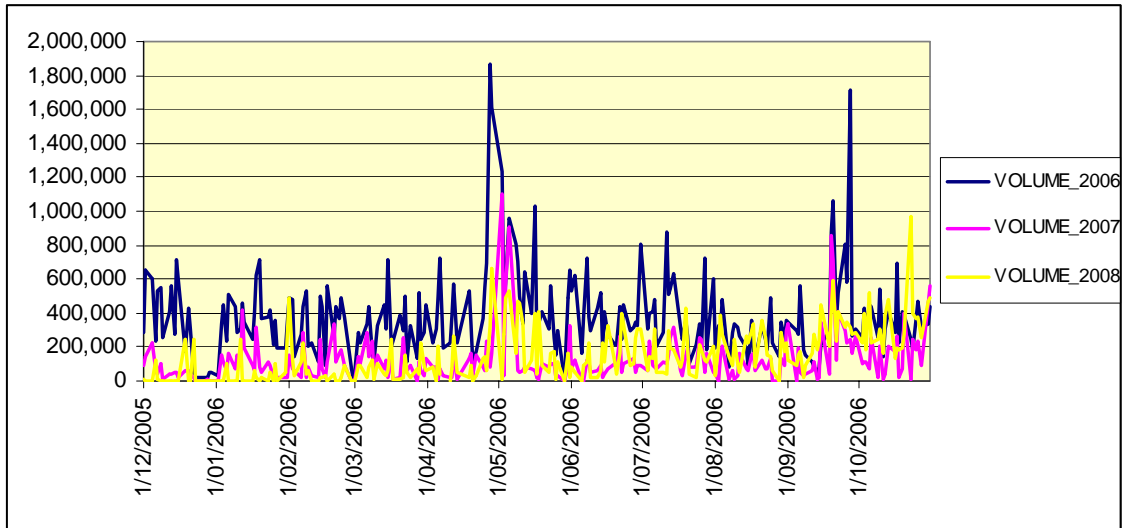
**Figure 27
Price of Carbon in Europe over the period April 2005 to June 2006**



Source: E3 International, The EU emissions trading scheme, July 2006

Figure 28 show the London Emissions Brokers Association (LEBA) volume index for 2006, 2007 and 2008 contract deliveries.

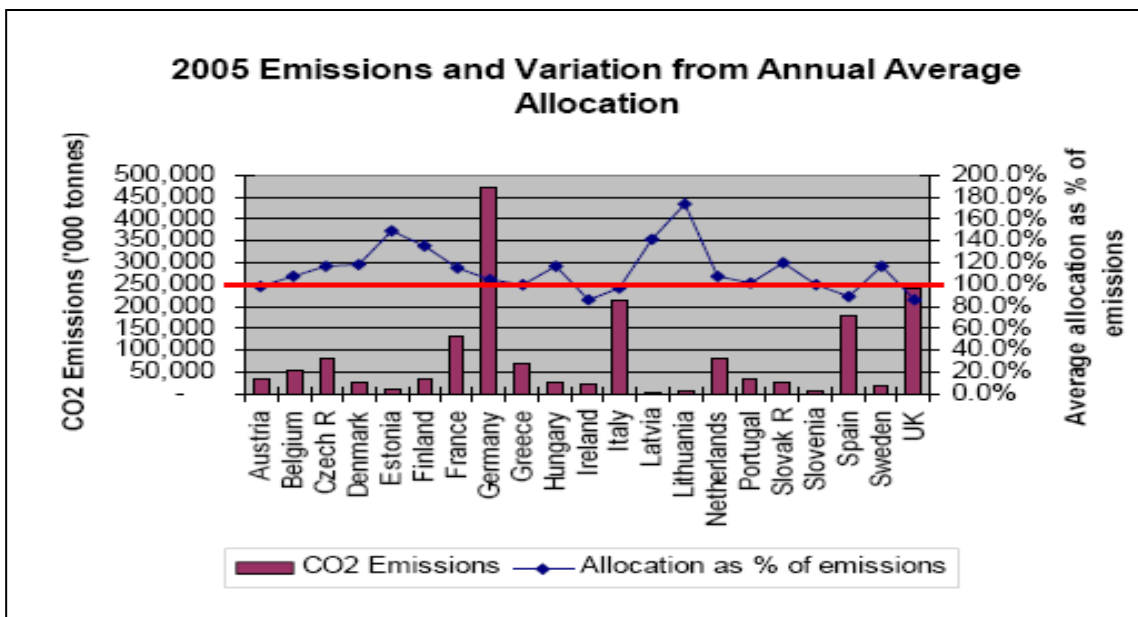
Figure 28
LEBA Volume Index – 2006 -2008



Source:LEBAA

Figure 28 illustrates the actual emissions in 2005 against allocations for each country in the EU. The variance between emission and allocations is a key driver for the downward EU carbon price spiral in 2005 as depicted in figure 27.

Figure 29: Actual emissions in 2005 against annual average allocations



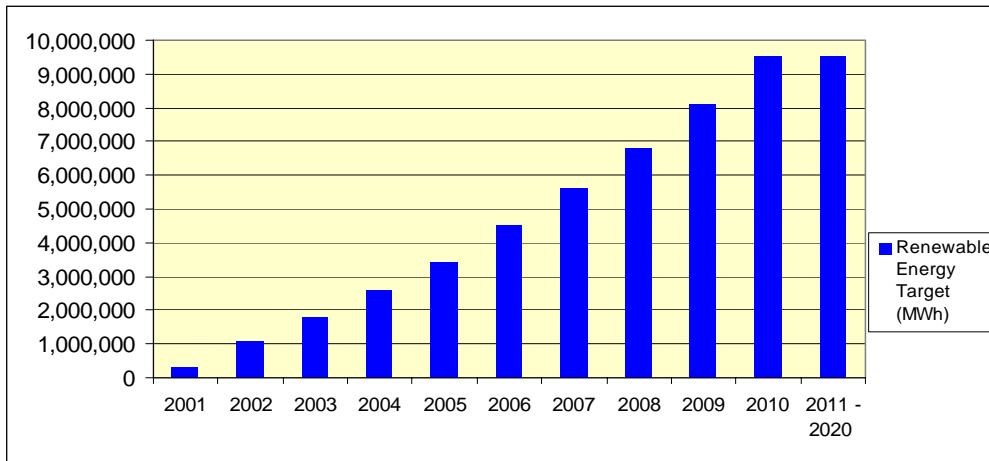
Source: E3 International

5.4 Trading activity in the REC and NGAC schemes in Australia

5.4.1 Renewable Energy Certificates (RECs)

Figure 30 graphs the mandated renewable energy target through to 2020.

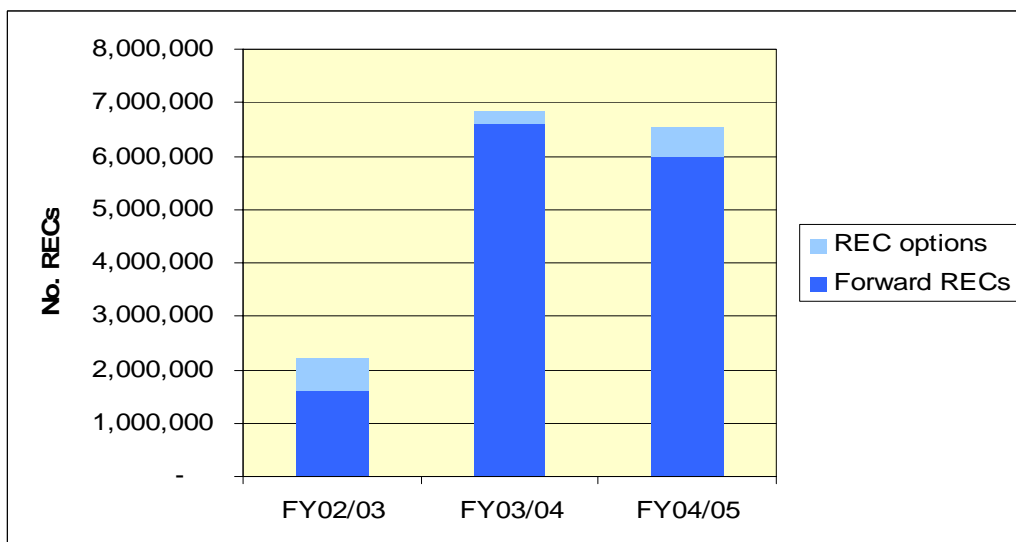
Figure 30 Renewable Energy Target Levels



Source: ORER

Figure 31 shows REC forward and option turnover trends for financial years from 2003 – 2005.

Figure 31
 Turnover in Forwards and Options: 2003 - 2005

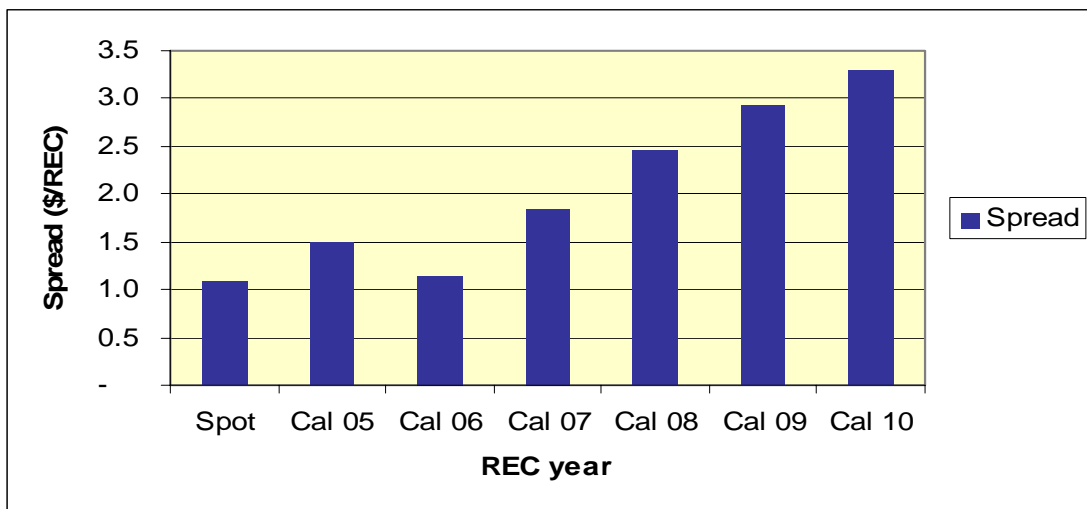


Source: AMFR

Note that in both FY03/04 and FY04/05 the volume of reported REC trades, as captured by the 2005 AFMA report is slightly above the number of RECs required as part of the annual renewable energy target shown in Figure 30.

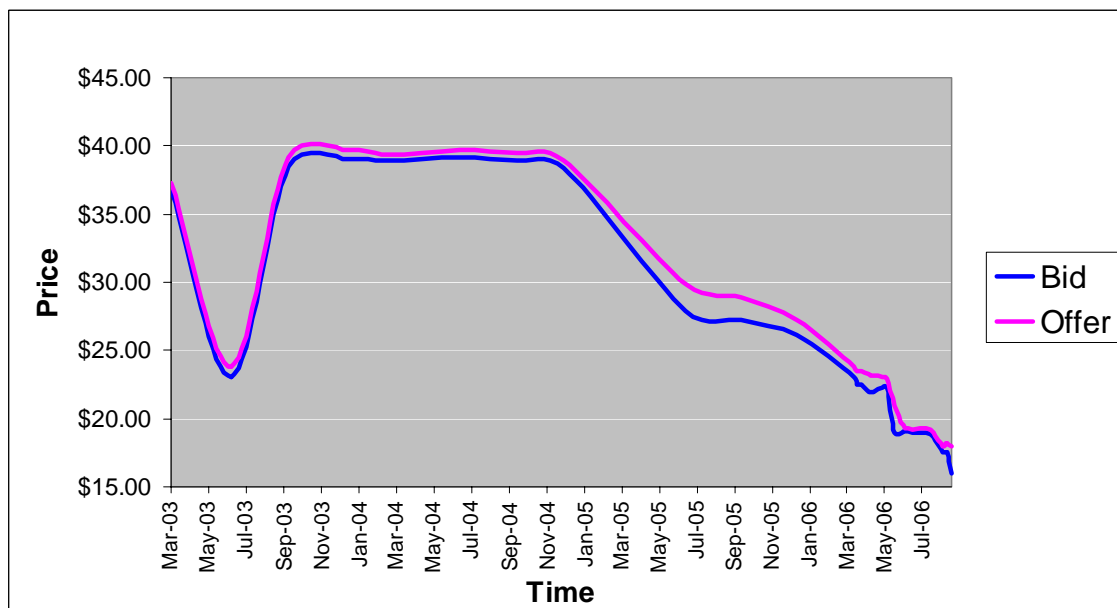
The spreads associated with REC trades varying quite significantly according to creation year and volume of RECs transacted. Figure 32 summarises spreads on RECs traded during 2006. Note that the wide spreads for forward RECs from 2008 and above.

**Figure 32
REC Spreads from January 2006 to October 2006**



Source: Broker data

**Figure 33
REC Spot Bid / Offer Data - Mar 2003 to Sep 2006**



Source: AFMA data

The spot price movements highlight the large drop in REC prices in 2005 and 2006. This is due to a number of factors including the federal governments decision not to increase the MRET target as well as the perceived over supply of RECs in future as a result of a fixed REC target and a series of planned renewable energy generation projects.

5.4.2 NSW Greenhouse Abatement Certificates (NGACs)

Unlike the REC market, NGAC prices have remained quite strong with a gradual upward trend exhibited over time. However, liquidity in the forward NGAC market (particularly for large volumes) is relatively low and is subject to higher spreads as demonstrated in Figure 34.

Figure 34
NGAC spreads from January 2006 to October 2006

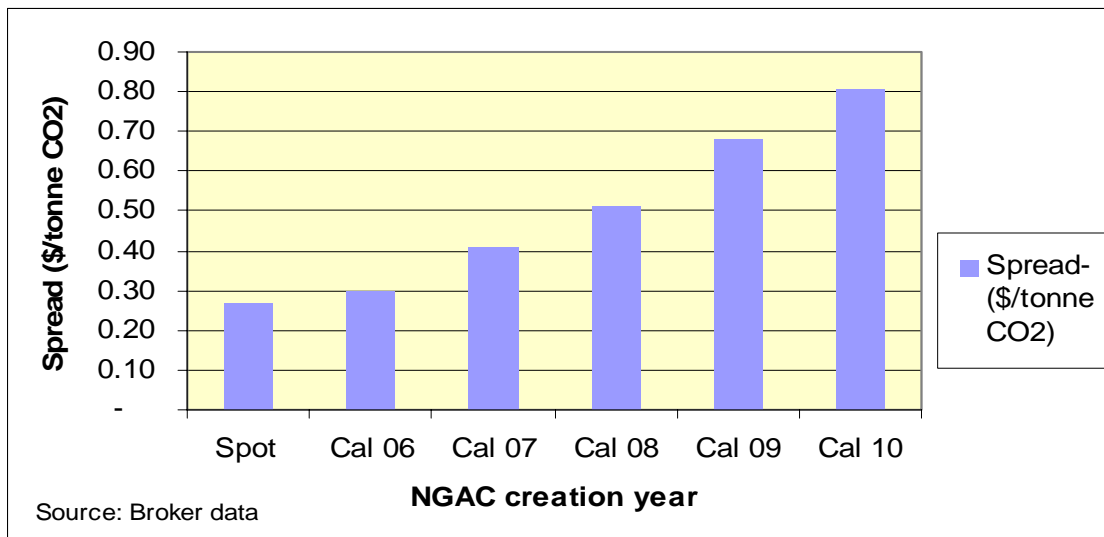
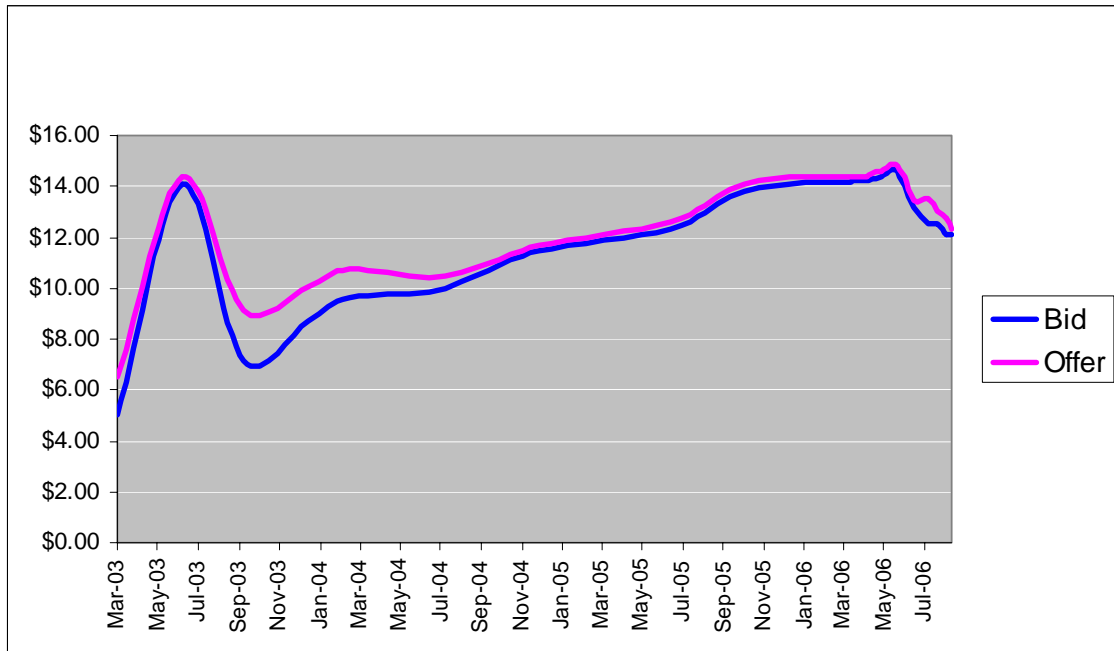


Figure 35 graphs NGAC spot bid and offer data over the period March 2003 to March 2006.

Figure 35
 NGAC Spot Bid / Offer Data - Mar 2003 to Sep 2006



Source: AFMA data

5.5 Recommendations

Recommendations

- The existing renewable energy schemes should be replaced by the adoption of a national emissions trading scheme that is capable of being implemented in a timely manner and integrated into a global scheme in the future. This issue has been examined as part of the accompanying report on Capital Markets and Investments which found a need for a consistent policy to price carbon emissions.

6 Inter-regional trade

This section considers:

- the role of inter-regional trade in the NEM;
- key issues identified in submissions to ERIG;
- the Settlement Residue Auction (“SRA”) process conducted by NEMMCO;
- use of financial instruments to hedge inter-regional risk; and
- potential enhancements to the SRA process that may promote inter-regional trade.

6.1 Overview

Findings

- The total settlement residues distributed since the introduction of the Settlement Residue Auction (SRA) process in 1999 exceeded auction proceeds received by NEMMCO. This outcome is as attributable to the nature of the instruments and auction process where participants bid for the right to receive an uncertain future cash flow. As noted in this report, the volume of settlement residues available through the auction depends on the actual level of inter-connector flows which may, on occasion, demonstrate a high level of variability. Accordingly, auction units may be less firm tools for risk management than other types of financial instruments available to market participants²⁰.

²⁰ Refer footnote 3

Recommendations

- Firming up SRA's through the re-design of the instrument (e.g. using auction proceeds to support price differences in conjunction with other arrangements to underwrite risk), conceptually, has merit and requires further analysis. However it is essential that the analysis considers the extent of changes to SRA prices, implications for financial link ratings, management of residual exposures to NEMMCO and parties involved in firming SRAs.

- Potential enhancements to the SRA instrument

Changes to the existing SRA instrument to promote inter-regional trade and risk management may include the following:

- Shorter-term SRAs
- Longer-term SRA units
- Peak and Off-peak SRAs

- Potential changes to the SRA process

- ERIG to commission a detailed analysis of the introduction of "firmer" SRA's and CSP/CSC schemes to fully assess the physical and financial implications of firming proposals and the risks, costs and benefits to participants and customers as opposed to allowing developments in transmission planning and operation combined with the gradual withdrawal of government ownership of energy businesses in the NEM and competitive forces to provide a market-based solution.
- NEMMCO to consider the introduction of short and longer -term SRA's as well as Peak/Off-peak products if there is sufficient support by participants. It is essential that proposals to change the SRA process take into account physical and financial market issues that impact on inter-regional trade.

6.2 Role of inter-regional trade in the energy market

A long standing focus for NEM participants and administrators has been the efficiency and effectiveness of inter-regional trade in facilitating energy price risk management. The issues raised in relation to this aspect of energy trading within the NEM are complex due to the interrelationship between the physical market and operation of financial markets.

Due to the regional structure of the NEM, inter-regional risks are assumed by market participants managing their load risks or using their contracting positions in one region to support retailing activities in another region.

Price differences between regions can arise due to numerous factors including:

- generator (unplanned) and transmission outages;
- physical limitations of the interconnecting links between regions; and
- generator bidding behaviour and interventions that affect the spot price setting process.

There are various risk management products and techniques available to NEM market participants to manage inter-regional risks. The most common include:

- inter-regional swaps and options;
- Settlement Residue Auction units (“SRAs”) obtained through the NEMMCO auction process as well as secondary units offered by other market participants and financial intermediaries; or
- intra-regional hedges i.e. aligning hedge product to the same region as the exposure.

Overseas energy markets utilise similar products and techniques but due to the differing market structures and pricing arrangements some markets increasingly utilise Firm Transmission Rights (“FTRs”) products to management risk rather than a non-firm product such as SRAs.

There are a number of different types of FTRs ranging from physically-related products to financial products delivering a right and obligation to buy power from location A to location B. FTRs and other mechanisms to manage inter-regional risk are addressed in this section.

An important role of inter-regional trade is to provide a mechanism to assist NEM participants to operate and manage a multi-region portfolio. In doing so, a number of benefits arise such as:

- increased trading activity across regions;
- diversity of risk management products is increased due to the entry of sophisticated financial players who actively utilise basis products such as inter-regional hedges to create leveraged trading positions; and
- more options to choose from when evaluating and formulating hedge strategies.

6.3 Key issues identified in submissions to ERIG

Key issues raised in the ERIG submissions are set out below.

- Submissions acknowledged lack of ‘firmness’ as a disincentive in using SRA’s as an inter-regional hedging instrument however the debate has centred on the mechanics of ‘firming’ the SRA process rather than firm SRAs per se;
- While some participants viewed lack of firmness as a disincentive to utilise SRAs financial intermediaries and active energy traders regarded this feature as presenting an opportunity to trade the product and thereby contributing to the competitive auction process and liquidity;
- Submissions also highlighted the need to consider the financial products currently available to manage inter-regional risk and the facilitation role that SRAs have in encouraging further inter-regional trade. SRAs cannot be viewed in isolation from the financial contract market as their impact on firm trade in other regions is relevant. For example, in a low liquidity environment as experienced in SA, the availability of VICSA and SAVIC SRAs enable Victorian swap positions to be “effectively” replicated into SA swaps using SRA’s;
- Augmentation or removal of the Snowy region was suggested by a number of participants in view of resolving a number of technical physical market issues as well as reducing the complexity of inter-regional hedging;
- A number of submissions expressed the view that the SRA market is operating as designed but minor enhancements should be considered to improve the effectiveness of the auction process and promote inter-regional trade.
- The Southern Generators proposal to deal with negative settlement residues was also subject to comment with a general of level of support noted; and
- Various submissions highlighted the importance of considering the overall gross pool market design including transmission planning, operation and access arrangements when assessing proposed changes to inter-regional residue management.

6.4 Settlement Residue Auction instrument

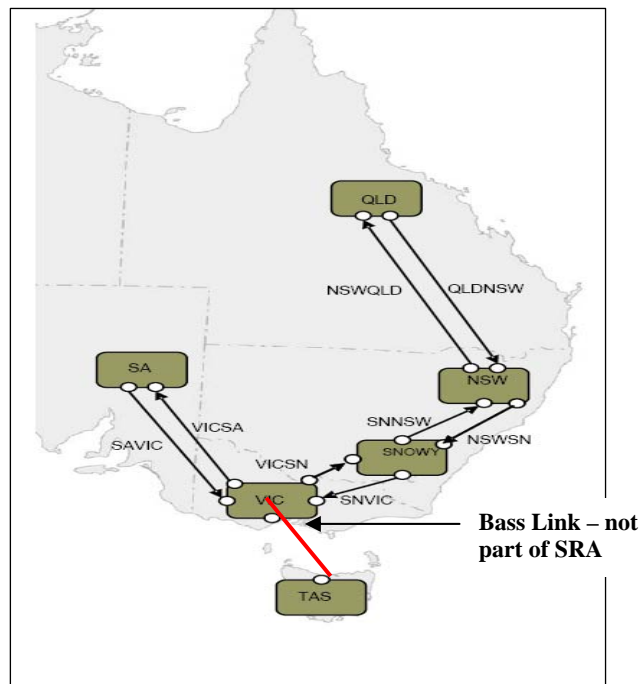
6.4.1 Auction process

NEMMCO administers a quarterly Settlements Residue Auction (“SRA”) process that allows registered participants to purchase SRA units and share in a pool of inter-regional settlement residue (IRSR) funds across directional inter-connector links.

The SRA process can be used to manage inter-regional price risk and promote inter-regional trade. SRAs are a non-firm product in that the payout to the holder is dependent on residues accumulating from the physical flow of energy across directional inter-connectors and hence are an imperfect hedging instrument. However, it is important to note that SRAs can be used as a hedging or speculative trading instrument and have encouraged the participation of financial intermediaries as well as incumbent energy market participants.

Figure 33 below shows the eight-(8) inter-connector links underpinning the SRA process.

Figure 33
Inter-connector Links in the NEM



Source: NEMMCO, CRA International

The Bass link inter-connector connecting Tasmania to the mainland is currently an unregulated inter-connector hence the residues accumulated across this link are not included in the SRA process. The inter-regional residues that accumulate on Bass link are passed on to Bass Link’s owner National Grid Australia (NGA) who distributes these to Hydro Tasmania. An agreement

between the Tasmanian government and the ACCC has allowed the import of inter-regional residues (IRRs) to be made available to the market through private commercial arrangements negotiated between Hydro Tasmania and interested parties, with any unsold import IRRs sold via an auction process overseen by the Government.

6.4.2 Inter-regional Settlement Residues (IRSRs)

The spot prices for electricity in each region of the NEM are determined by a number of key factors including:

- supply and demand;
- physical limitations of inter-connectors and constraints²¹; and
- loss factors in the distribution and transmission networks.

The difference between the value of electricity in the region where it is generated and the region sold is the inter-regional settlement residue (IRSR).

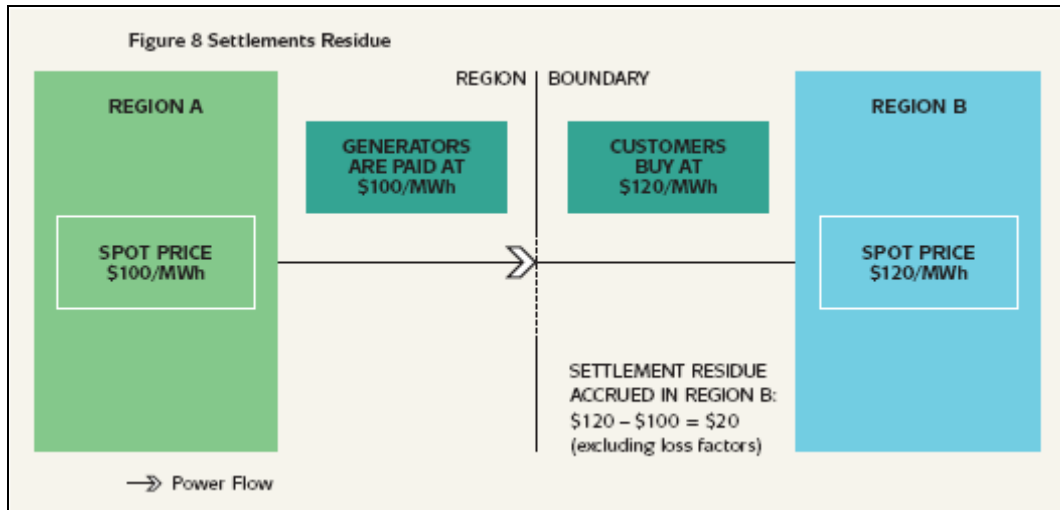
As part of the auction process market participants place bids for an entitlement to any IRSR that may accumulate across specific NEM inter-connectors. The volume of IRSR available through the auction depends on the actual level of inter-connector flows which can vary significantly over time. For this reason, SRAs are less firm than other financial instruments used to manage inter-regional risk. Figure 3 in Appendix C illustrates the variation in SRA firmness in comparison to a firm swap.

However, the SRA process delivers a common clearing price through a competitive auction and in essence represents fair market value for the potential residues being auctioned. In this regard, the prices received incorporate an assumption of non-firmness and hence volume risk assumed by auction participants.

The diagram on the following page outlines the concept of settlements residue.

²¹ See Appendix C.1 System constraints which show system constraints during system normal and system outage conditions

Figure 34
 Overview of the SRA Process

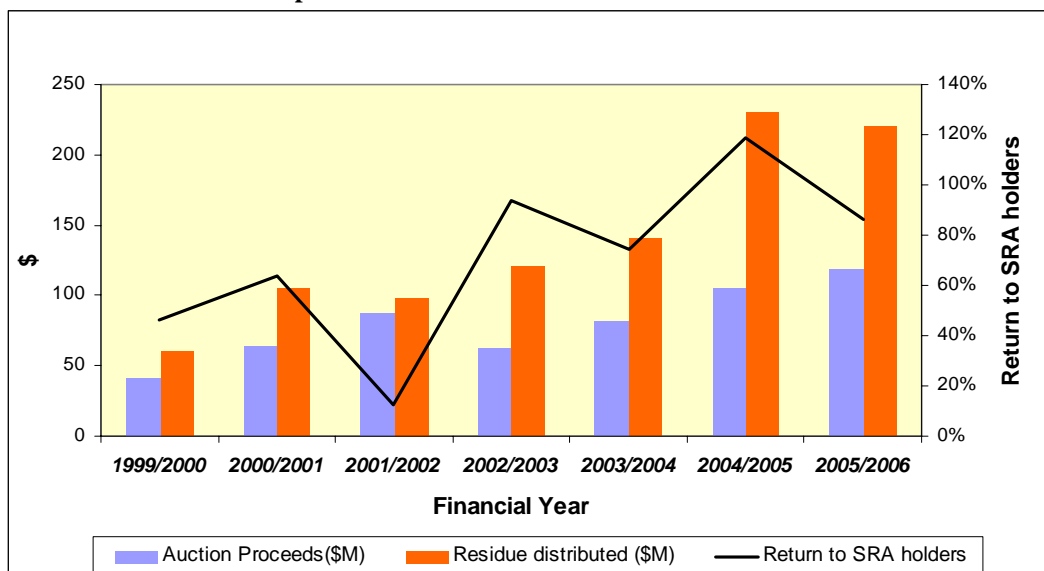


Source: NEMMCO, Trading arrangements in the NEM

6.4.3 Analysis of auction results

Since the start of the SRA auction process in July 1999, NEMMCO has calculated the difference between auction proceeds and residue funds distributed to be \$417M²². The three charts depict various statistics relating to the auction proceeds and residues distributed overtime.

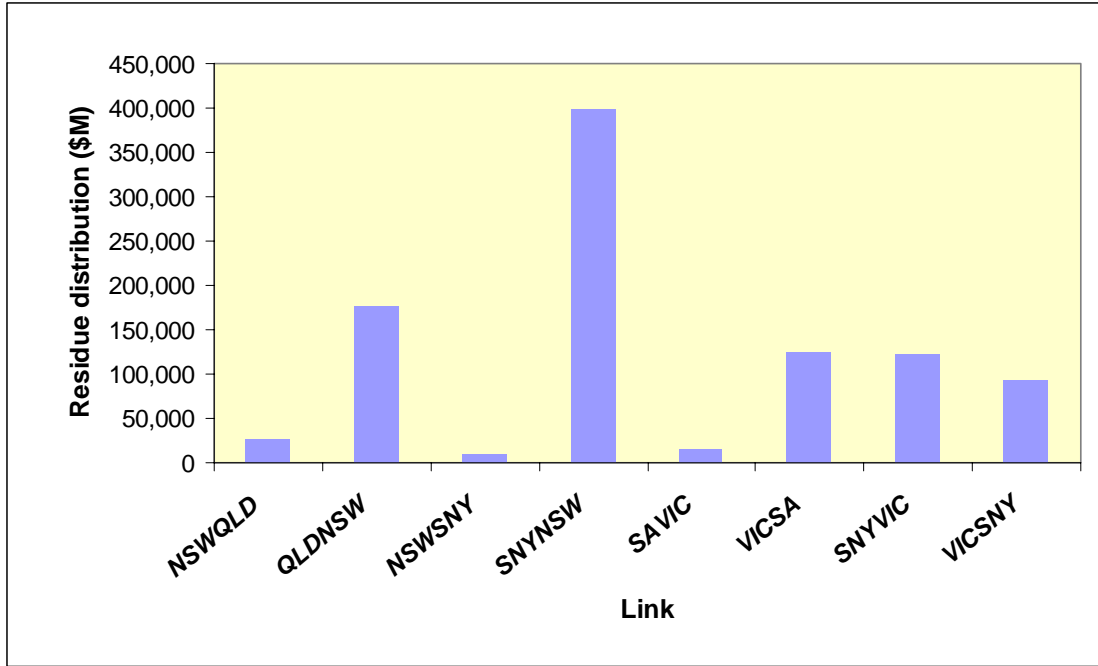
Figure 35
 Total SRA proceeds versus Residue distribution to SRA holders



Source: NEMMCO

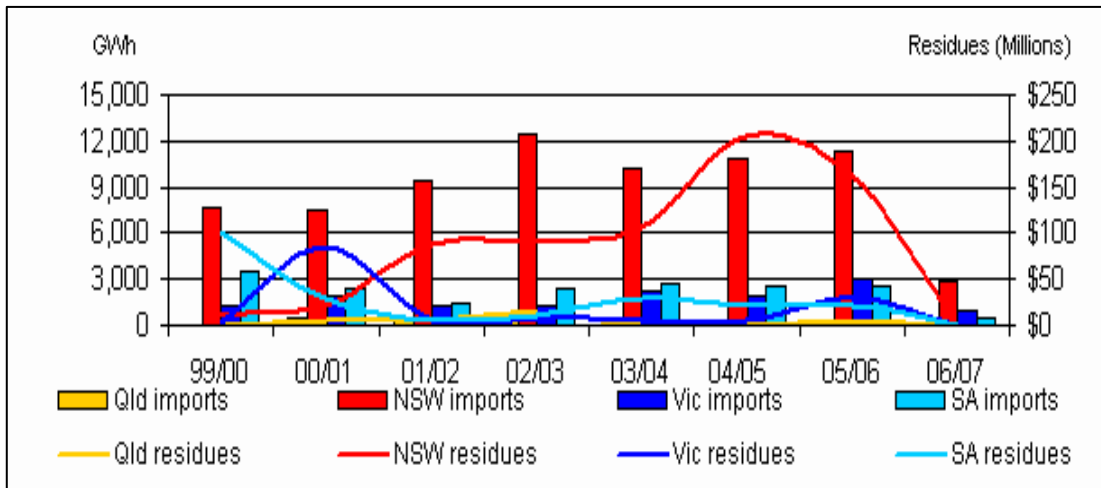
²² NEMMCO submission to ERIG, 2006

Figure 36
IRSRs Distributed by NEMMCO for each Inter-connector Link: 2000/01 to 2005/06



Source: NEMMCO SOO

Figure 37
Inter-regional Residue Accumulated Against Imports by Region



Source: AER

6.4.3.1 Auction Participants

There are currently twenty eight (28) participants eligible (i.e. registered) to purchase SRA units. NEMMCO’s submission to ERIG noted that of current 28 registered SRA participants 6 are traders, 14 generators and 8 retailers – 9 retailers and generators are from Victoria. Anecdotal evidence suggests that only six to seven actively participate in SRA auctions.

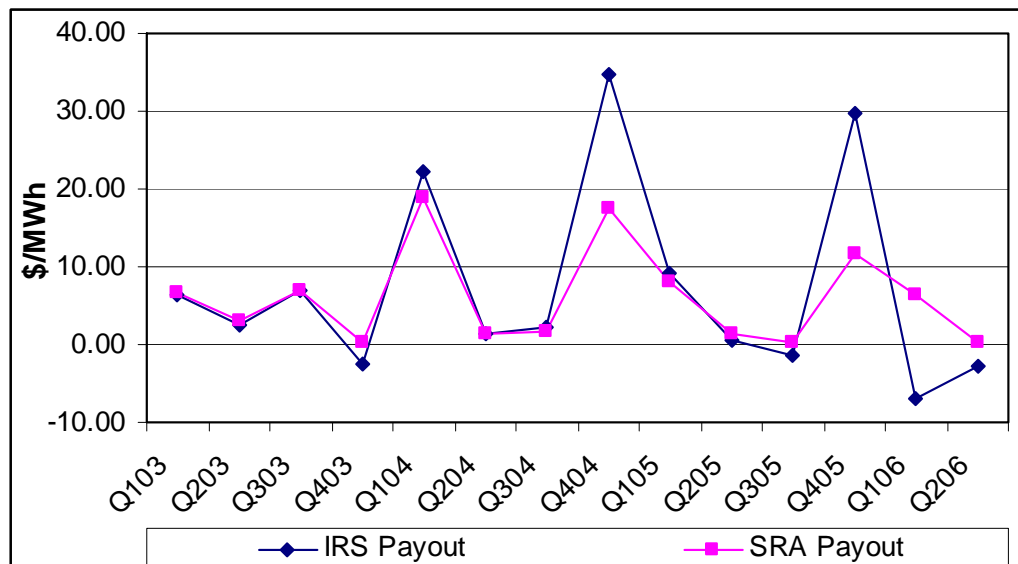
Relatively low participation by most government owned retailers and generators in NSW and QLD is a contributory factor. A key issue here is that the aggregate load represented by these entities is quite large as a portion of total NEM load. It is probable that if this load was under private ownership inter-regional exposure would increase encouraging greater participation in inter-regional trade with a consequential benefit to the auction process. The current QLD sale process and removal of the LEP and ETEF is likely to assist in this regard.

6.4.3.2 The relationship between swaps and SRAs

The relationship between SRA and inter-regional swaps varies over time. Some inter-connector links exhibit a closer correlation to firm inter-regional spreads whereas others are more variable due to transmission constraints and other physical factors that affect inter-connector flow and hence SRA payoff.

Figure 38 illustrates the relationship between SRA payoffs and Inter-regional swap payoffs across the VIC to NSW inter-connector.

Figure 38
SRA Payout Against Inter-regional Swap Payout - VIC to NSW



Source: Hydro Tasmania

As mentioned previously, inter-regional swaps are firm instruments by virtue of comprising a fixed volume but introduce the risk of negative returns due to potential of one region trading

below the other region i.e. in a different direction to that intended when transacting the inter-regional swap.

This is demonstrated in the chart above, particularly in Q1 and Q2 06. e.g., SRA units actually exhibited payoffs greater than that of the inter-regional swap in some time periods. Refer See Appendix C, Figure 3 for supplementary analysis on firmness of SRAs across each inter-connector link assuming a hypothetical “firm” interconnect flow at the MW equivalent of the number of SRAs units available through the auction process.

6.4.4 Common financial market approaches to manage inter-regional risk

As mentioned previously, there are a number of ways to manage inter-regional risk within the NEM which range from the use of inter-regional swaps through to the use of SRAs in conjunction with swaps to replicate a firm inter-regional swap position.

Sophisticated energy trading entities within the NEM operate highly structured multi-region portfolios that utilise a combination of swaps, options and SRAs to dynamically manage changing inter-regional risk arising from load, price and structural changes within the NEM.

Appendix C includes an example of techniques that can applied to manage inter-regional risk.

6.5 Enhancements to SRA process to facilitate inter-regional trade

Overseas energy markets provide a number of lessons in evaluating potential enhancements to the SRA process, particularly in relation the type of market structures implemented and its impact on inter-regional trade.

Specifically, the gross pool market design in Australia is one of the few such markets in the world. Numerous studies and debates have attempted to conclude on which market design (i.e. Net pool model versus Gross pool) is best but in essence it appears that are other factors that probably have a greater bearing on the success of the market over time.

Some of these factors are:

- the balance of government and private asset ownership;
- vertical integration and competition;
- government policy;
- geography and size of the market;
- physical characteristics and technical specifications;

- incentives for new investment; and
- minimising power prices for consumers.

In this regard, there are a number of positive developments emerging in Australia that have the potential through competitive market forces to facilitate increased inter-regional trading activity including:

- the announced removal of ETEF in NSW from 2010 and the sale of Queensland retail businesses to the private sector;
- the entry of Tasmania into the NEM;
- increased participation of financial intermediaries, non-asset backed market participants and institutional investors in NEM and related derivative trading;
- the increasing success of the SFE futures market in facilitating trade;
- adoption of the Southern Generators proposal for managing negative settlement residues; and
- significant transmission planning and design efforts by a number of parties such as the AEMC.

Whilst a number of submissions to ERIG from a cross-section of NEM participants have commented that the SRA market is operating as designed and there is no further need for government intervention, a number of potential enhancements have been suggested to encourage increased participation in inter-regional trade and improve risk management.

These proposals include:

1. Firming up SRAs by utilising the SRA auction proceeds to support payments to SRA holders potentially in conjunction with insurance support
2. Changes to the SRA auction process ranging from the extension of the term of SRA units through to shortening the term to improve liquidity in the short-term market. The creation of peak and off-peak SRAs products has also been contemplated
3. Removal of the Snowy region and use of constraint support payments (CSPs) in conjunction with constraint support contracts (CSCs) to effectively simulate a full nodal pricing system
4. Introduction of Firm Transmission Rights (FTRs)
5. Adoption of full nodal pricing (refer section 4 for discussion on potential impact on financial market liquidity)

6.5.1 Firming SRAs

6.5.1.1 Summary of issue and recommendation

Various submissions acknowledged the issue of lack of firmness although in many cases the context focused on the appropriate policy response to ‘firming’ SRAs and the potential risks of introducing major changes, particular in isolation to initiatives to improve transmission performance and participant behaviour. Market participants are currently pricing these risks through the SRA auction process and their associated derivative hedging activities.

Firming up SRA’s through the design of the instrument (e.g. using auction proceeds to support price differences), conceptually, has merit and requires further analysis. Proponents in favour of ‘firming’ SRA argue this would lead to higher auction prices and ultimately reduce costs for consumers. However, it is difficult to isolate and quantify the costs and benefits of firming SRAs without consideration of the physical and financial factors raised in this section as well as energy policy issues more generally.

A comprehensive assessment of the risks to be addressed and the costs and benefit of financially firming SRAs is warranted. The assessment would need to address the complex issues involved in underwrite the financial risks relating to, inter alia, transmission performance and participant behaviour. The assessment would need to consider:

- whether the historical net residues distributed are likely to occur in the future as government intervention through ownership of energy businesses in the NEM diminishes in Queensland and ,potential overtime, in NSW; and
- the incremental premium cost, mechanics and net benefits from underwriting firmness and who bears the risk premium. Specifically, the analysis should considers the extent of changes to SRA prices, implications for financial link ratings, impact on inter-regional trading activity and liquidity, management of residual exposures to NEMMCO and parties involved in firming SRAs.

6.5.1.2 Firmness can be addressed by hedging using derivatives

Firmness can be provided by transacting inter-regional swaps with market participants or on the futures exchange, for example:

- utilising swaps, futures and options to implement firm inter-regional hedging positions;
- forming a view of SRA firmness and purchasing an increased amount of SRA units to account for the lack of firmness. For example, If SNY to NSW is rated at 50% and the position to be hedged is 10MW, purchase 20 units; or

- transacting SRA derivatives through financial intermediaries and other active market participants. As such participants form a view about the potential firmness of SRA's pre-auction and this will drive their bid prices and strategy.

6.5.2 Enhancements to the SRA instrument

Suggested changes to the existing SRA instrument to promote inter-regional trade and risk management include the following:

- Shorter-term SRAs

Repackaging the existing quarterly IRSR product to incorporate a percentage of shorter-term SRA units (e.g. week ahead or day ahead). This may provide further capacity for market participants to manage inter-regional risk and could lead to increased liquidity in the broader market, particularly in the short-term market.

- Longer-term SRA units

This development would support longer term inter-regional positions for market participants who purchase the units however particular attention to the design of these unit is required to ensure that hoarding does not occur with a resulting decrease in liquidity and inter-regional trading activity.

- Peak and Off-peak SRAs

Creation of peak and off-peak SRAs to better facilitate exposure management in the absence of an active short-term hedge market. Support from market participants will need to be gauged prior to pursuing this option.

The costs associated with implementing these initiatives are likely to be largely IT and administration related but need to be assessed to determine whether the implementation is feasible.

6.5.3 Changes to the SRA process

Due to the complexities of inter-regional trade and the fact there are numerous financial and physical factors at play, it is out of the scope of this report to recommend definitive outcomes that should be implemented. Rather, the approach has focussed on examining the evidence and literature available in conjunction with market analysis to put forward suggestions for further consideration, these include:

- Undertake detailed analysis of the introduction of "firmer" SRA's and CSP/CSC schemes. We are not aware of any cost benefit analysis in the studies completed to date, but expect this to guide ERIG's deliberations. A specific project may be required to fully assess the physical and financial implications of firming proposals.

- Consider changes to the SRA Auction process such as the introduction of short-term SRA's, longer term SRA's as well as Peak/Off-peak SRA's if supported by participants to encourage further inter-regional trading activity. However, it is essential that proposals to change the SRA process must take into account physical and financial market issues that impact on inter-regional trade.
- Given the numerous developments in the market at present and the relative immaturity of the NEM, it may be beneficial to focus on improving the efficiency of the physical market and allowing the financial market to self-develop and drive changes to or innovations around the SRA unit and inter-regional trade in general.

6.5.4 Market design considerations

6.5.4.1 Boundary review/Snowy removal

Regional redesign focussing on the Snowy region has been proposed by a number of submissions to ERIG. Conceptually, the removal of the Snowy region is likely to simplify inter-regional trade as one less node would be required as part of an inter-regional hedging strategy involving NSW and VIC nodes e.g. rather than purchase VIC to SNY and SNY to NSW SRAs a direct VIC to NSW SRA would be required.

The Snowy region removal proposal is a complex issue that needs to be thoroughly analysed in light of the potential impact on:

- financial market activity;
- contractual arrangements that reference the Snowy region (there is anecdotal evidence that some large, reasonably long-term contracts exist);
- transmission planning and policy; and
- constraints and congestion e.g. consider impact of introducing CSC/CSP (Constraint Support Contracts /Constraint Support Pricing) in isolation on the Snowy region versus other constraint points within the NEM.

CSP/ CSC's (currently trialled in the Snowy region) are complex arrangements that essentially allow participants the ability to trade around mathematical constraints that act to bind the network. In essence these agreements can return similar results to a full nodal pricing arrangement if all the constraints in the system are covered. As discussed by the 'Insider Report issue 004' produced by Intelligent Energy Systems (IES), *"unless this approach is implemented for ALL constraints, there is a risk of perverse pricing outcomes in particular locations, with resulting distorted and unpredictable incentives."*

Further, whilst CSC's may provide local pricing signals as would be delivered by a full nodal pricing system practical implementation issues as well as the effect on the dynamics of the NEM need to be thoroughly considered.

6.5.5 FTRs

- Implementing FTRs required can be problematic due to difficulties in allocation of risk and creating the incentives to undertake congestion management as well as the difficulty in developing an operational framework for trading FTRs
- The Parer Review recommended FTRs with NEMMCO as the appropriate party to auction and manage an FTR market.

There are a number of potential issues associated with this outcome such as:

- The trigger for transmission augmentation has been nominated as the traded price of firm FTRs. This is likely to promote anti-competitive behaviour and not likely to be an appropriate benchmark.
- NEMMCO may be required to introduce arrangements to economically underwrite significant exposure with this cost borne by market participants. Basis and credit risk would ultimately lie with NEMMCO and hence may promote the use of FTRs as an inter-regional swap alternative due to the free credit mitigation provided.
- The sale of long term FTRs (up to 5 years) is not likely to increase inter-regional trade and competition as it may promote hoarding and suppress price signals.
- FTRs as a firm product can be synthetically created using existing financial derivatives available to NEM participants. However, the current SRA process is more akin to a non-firm option hence exact replication via a firm transmission product would require the combination of a swaps and options.
- Due to numerous various factors affecting transmission such as weather, demand level and generation as well as other factors that are difficult to hedge, transmission products cannot be 100% firm. For this reason, management of these risk factors is probably best left to participants who can manage their physical generation and demand as well as purchase the appropriate hedge (or insurance) contracts to mitigate these risks.

6.5.6 Full nodal pricing

- Full nodal pricing models are very complex and whilst it can be argued that they provide more accurate locational pricing they generally do not increase liquidity in power markets. The New Zealand (NZ) market is a good example of this with very limited liquidity and little contract trading. However, other factors such as vertical integration have also impacted

the NZ market reinforcing the need to assess changes to market design very carefully and thoroughly to ensure that accurate judgements are made.

- Changes made to the number of regions within the NEM (particularly an increased number of regions) will increase the complexity of the market and potentially reduce liquidity.
- Existing long-term structured contracts that reference current NEM regions may need to be re-negotiated with a resulting change in market value.

6.6 Recommendations

Recommendations

- Firming up SRA's through the re-design of the instrument (e.g. using auction proceeds to support price differences in conjunction with other arrangements to underwrite risk), conceptually, has merit and requires further analysis. However it is essential that the analysis considers the extent of changes to SRA prices, implications for financial link ratings, management of residual exposures to NEMMCO and parties involved in firming SRAs.
- Potential enhancements to the SRA instrument

Changes to the existing SRA instrument to promote inter-regional trade and risk management may include the following:
 - Shorter-term SRAs
 - Longer-term SRA units
 - Peak and Off-peak SRAs
- Potential changes to the SRA process
 - ERIG to commission a detailed analysis of the introduction of "firmer" SRA's and CSP/CSC schemes to fully assess the physical and financial implications of firming proposals and the risks, costs and benefits to participants and customers as opposed to allowing developments in transmission planning and operation combined with the gradual withdrawal of government ownership of energy businesses in the NEM and competitive forces to provide a market-based solution.
 - NEMMCO to consider the introduction of short and longer -term SRA's as well as Peak/Off-peak products if there is sufficient support by participants. It is essential that proposals to change the SRA process take into account physical and financial market issues that impact on inter-regional trade.

7 Vertical and Horizontal Integration in the NEM

7.1 Overview

Findings

- Vertical and horizontal integration is increasingly a defining characteristic of evolving electricity market in Australia driven by corporate strategies to create shareholder value from asset portfolios and financial and capital market incentives to reduce cost of capital. In this regard, the three integrated private sector energy retailing groups operating in the NEM share common business strategies.
- Infrastructure investors and some merchant generation businesses are providing debt financing or hold direct equity interests in emerging retailing businesses across the NEM.
- The sale of government owned retailing businesses is likely to promote further consolidation in the NEM and reinforce the focus on building and controlling the despatch of peaking plants to manage aggregated load risks.
- In many respects, horizontal integration poses more challenges for the NEM both in terms of leaving state-based government-owned merchant generators reliant on the bilateral contracting market with NEW-wide retailers to manage price risk and cash flow volatility and, secondly, the effectiveness of the NEM prudential framework in detailing with credit-induced event risk in the NEM.

Recommendations

- While vertical integration is often viewed as the basic problem of market liquidity this issue should be left to market forces and the existing regulatory framework for dealing with competition issues to resolve.

7.2 Market participants in the NEM

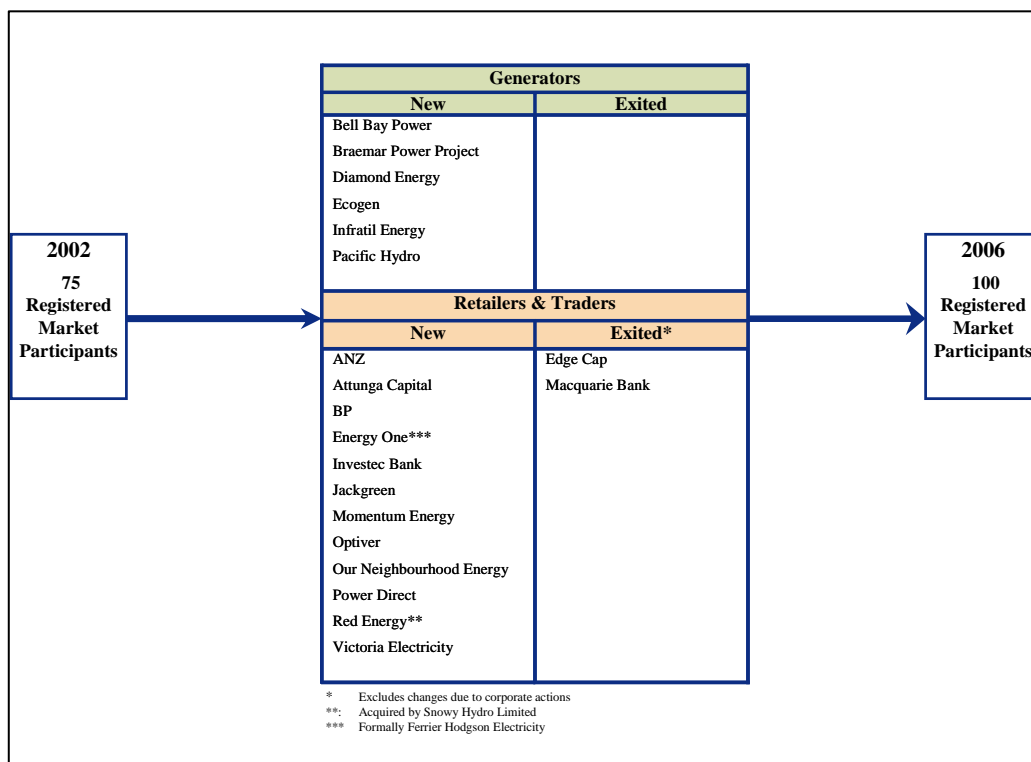
7.2.1 New entrants

Figure 40 identifies the principal changes in market participants over the period from 2002 to 2006. New entrants include energy retailers targeting particular market segments, energy traders contributing to emerging liquidity in futures and broker-intermediated segments of the

forward markets and infrastructure investors with portfolio interests in generation assets and retail businesses.

The analysis confirms the findings of a KPMG survey of investor attitudes on development opportunities in the NEM. Significantly, active participants or interested parties include Westpac, ANZ, BP, Investec Australia, Infratil and Arunga Capital.

**Figure 40
Registered Participants in the NEM from 2002 - 2006**



Source: NEMMCO, Public Announcements, KPMG Analysis

7.2.2 The trend towards vertical and horizontal integration

Vertical and horizontal integration is a common phenomenon in global energy markets but more particularly the UK electricity market. The NEM is exhibiting a similar trend with the emergence of a few, large vertically integrated energy businesses, government owned merchant generators and new entrant retailers targeting niche market segments.

This landscape is vastly different to the initial ownership structure envisaged at the start of the energy reform process. While proponents of a competitive electricity market may see the trend towards re-integration as an indication of the need for policy reform, other regard the process as evidence of free market development within existing competition policy framework.

In our view, vertical and horizontal integration is increasingly a defining characteristic of an evolving electricity market driven by corporate strategies to create shareholder value from asset portfolios and financial and capital market incentives to reduce cost of capital. In this regard, the three integrated private sector energy retailing groups operating in the NEM share common corporate strategies and, not surprising, comparable credit ratings.

Table 3 highlights the key changes in ownership and economic interest interests held in generation portfolios and retailing businesses since 2002.

Table 3
Major Changes in Ownership and Economic Interests in
Retailing and Generation Businesses since 2002

Year	Acquirer	Acquired	Comment
2002	Origin Energy	Citipower	Retail business purchased from CKI and HEH
2004	AGL – Retailer	32.5% economic interest in Loy Yang A	Major base load generator in Victoria
2004	Infratil Energy Australia	Victoria Electricity	Acquires equity investment
2005	CLP – Yallourn Energy/ Auspower	Singapore Power	CLP owners of Yallourn Energy and Auspower purchased the TXU energy business from Singapore Power
2005	AGL - Retailer	Southern Hydro	Acquired from Meridian Energy Limited
2005	Babcock & Brown	Jackgreen Limited	Acquires substantial shareholding in listed energy retailer
2004	Snowy Hydro	Red Energy	Victorian based energy retailer
2006	Ergon Energy	Powerdirect	Listed for sale by Queensland government in October 2006
2006	Sale in progress - October 2006	Sun Retail	Largest retailer in Queensland disaggregated from ENERGEX

Source: Company accounts, ASX announcements

Significantly, new entrant retailers with limited access to the capital markets and contingent forms of capital tend to have substantial shareholders with interests in generation portfolios (Jackgreen and Victoria Electricity), supported by investment banks or owned by a generator

(Red Energy). Investec Bank of Australia currently provides finance facilities to Energy One as part of an ongoing strategic relationship.

7.3 Vertical integration

7.3.1 Emergence of integrated energy businesses

There are three integrated energy businesses operating in the NEM in 2006: AGL Energy, Origin Energy and TRU energy (“integrated energy retailing businesses”).

These businesses are characterised by:

- dual fuel electricity and gas retailing businesses;
- equity or financial interests in upstream gas assets;
- direct equity or indirect financial control of despatch of base load or peaking generation assets to mitigate exposure to wholesale electricity spot market prices on retail businesses;
- retail businesses operating in multiple regions; and
- investment grade rating.

Table 4 compares the business models of the major private and publicly owned energy retailers operating in NEM. The business models of the integrated energy businesses are broadly comparable varying only in the degree of equity versus financial interest in power generation assets and gas production, coverage within the NEM and scale of operations.

Table 4
Composition of Businesses of Major Energy Retailers in the NEM

	Energy Group	Retailing Businesses		Generation Portfolio			Equity Interest in Upstream Gas/Oil Assets	Long Term Gas PPA
		Electricity	Gas	Coal	Hydro/Renewable	Gas		
Private	AGL	✓	✓	✓	✓	✓	✓	✓
	Origin Energy	✓	✓			✓	✓	
	TRU Energy	✓	✓	✓		✓		✓
Government Owned	Country Energy	✓	✓		✓			
	Energy Australia	✓						
	Ergon Energy	✓						
	Sun Retail	✓	✓					

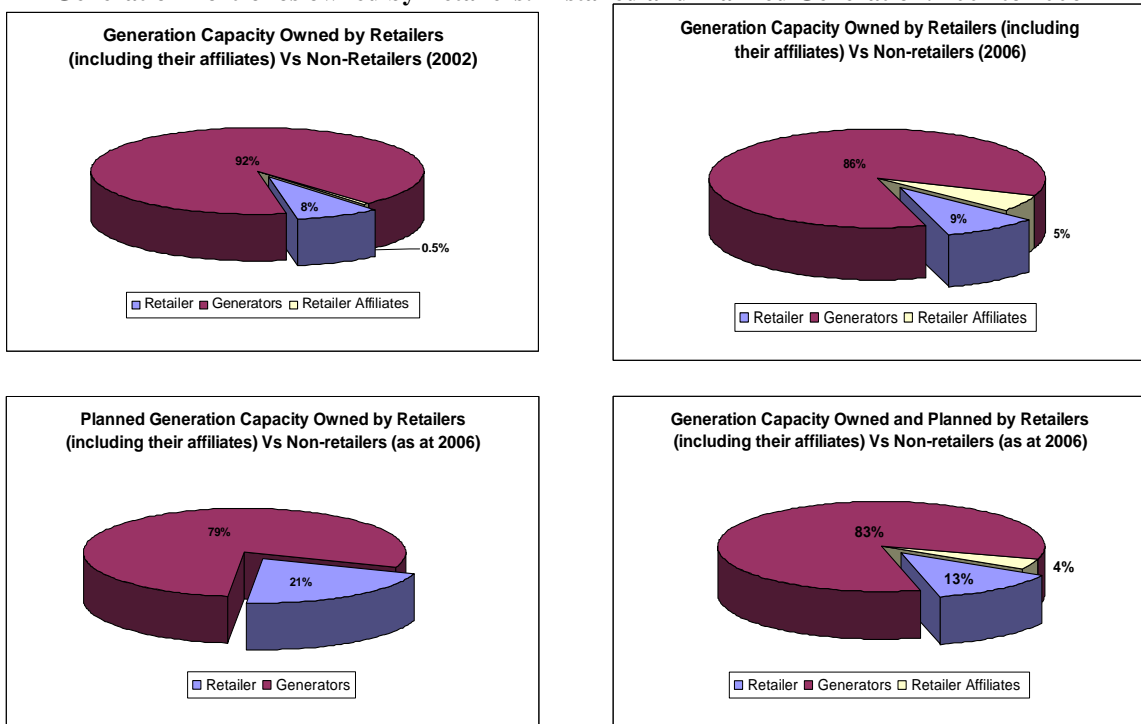
Source: Company websites
 Report on NEM Generator Costs (Part 2), Feb 2005, Acil Tasman

7.3.1.1 Ownership of generation portfolios

Figures 41 - 44 highlight the increasing importance of generation portfolios to manage retail and mass-market load exposure to wholesale electricity price and volume risks.

Over the four-year period from 2002 to 2006, the three major electricity retailers in the NEM increased their direct and indirect economic interest in installed capacity from 8.5 per cent to 14 per cent through acquisition of generation assets, particularly in Victorian and South Australia.

Figures 41 to 44
Generation Portfolios owned by Retailers: Installed and Planned Generation: 2002 to 2006



Source: NEMMCO, KPMG Analysis

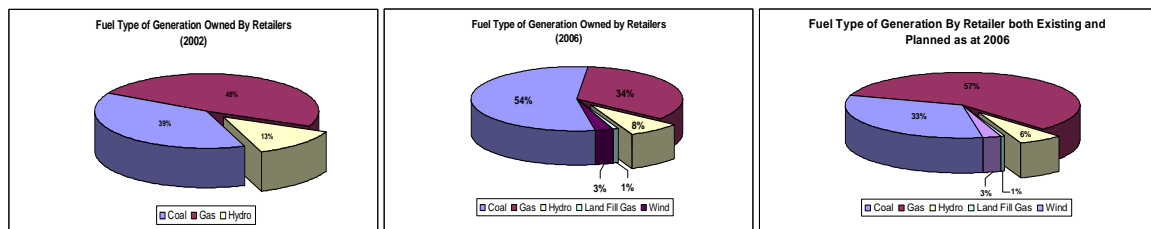
This economic interest in the NEM generation portfolio is likely to increase to 17 per cent if planned investments in generation assets are commissioned. As an indication of the importance of option products in managing price volatility and load risks, energy retailers are committing significant capital to investments in peaking assets. Importantly, merchant generators are continuing to invest in base load capacity.

Planned investment in peaking plants is a prudent response to the exposure to spot price risk during periods of high price volatility. While financial derivatives may provide a commensurate financial hedge, the acquisition of Southern Hydro by AGL in 2005 reduced the liquidity for long-term structured cap products increasing the cost of financial hedges and reducing the strategic benefit of direct equity investment.

Southern Hydro (renamed AGL Hydro Partnership) combined with AGL’s existing gas-fired peaking plants allows 80 per cent of the peak component of its load exposed to wholesale spot price risk to be internalised between its generation and retail businesses.²³

The importance of peaking generation is evident in Figures 45 to 47 showing the fuel source of generation portfolios. Control of gas-fired generation is designed to optimise upstream gas production assets.

**Figures 45 to 47
Fuel source mix of generation portfolios**



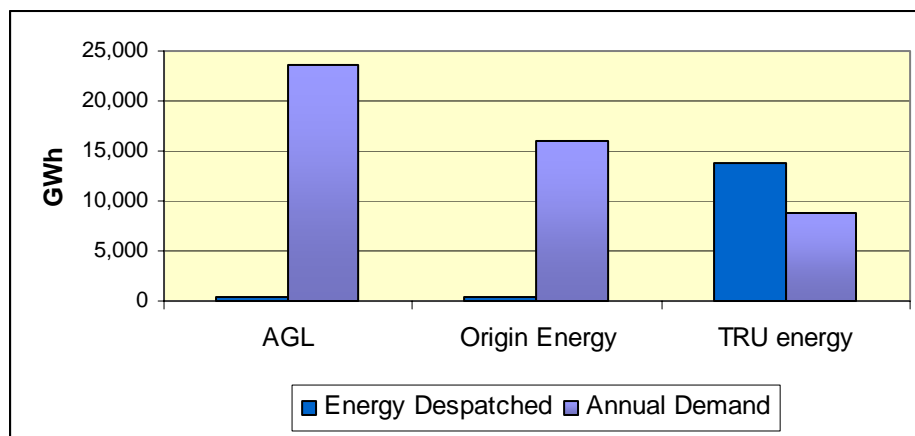
Source: NEMMCO, KPMG Analysis

²³ Standard and Poors rating August 2006

7.3.2 Implications for market liquidity

Figure 48 compares the degree of vertical integral of the three integrated energy businesses. Apart from TRU energy, only a small percentage of the load of other groups is economically hedged through generation.

Figures 48
Analysis of Energy Despatched and Demand of Integrated Energy Groups



Source: NEMReview, KPMG Analysis

Vertical integration is often viewed as the basic problem of market liquidity. However, for major groups focused on creating shareholder value, improving their credit rating and reducing the cost of capital will necessarily involve hedging their portfolio of business and financial risks through ownership of thermal and renewable generation assets, bilateral long-term power purchase arrangements and complex derivative hedging products and energy trading strategies.

The issue of when does vertical integration lead to illiquidity should be resolved with the existing regulatory framework for dealing with competition issues in the first instance and market forces more generally.

In many respects, horizontal integration poses more challenges for the NEM both in terms of leaving state-based government-owned merchant generators reliant on the bilateral contracting market with NEW-wide retailers to manage price risk and cash flow volatility and, secondly, the effectiveness of the NEM prudential framework in detailing with credit-induced event risk in the NEM.

7.4 Recommendations

Recommendations

- While vertical integration is often viewed as the basic problem of market liquidity this issue should be left to market forces and the existing regulatory framework for dealing with competition issues to resolve.

8 Government intervention

8.1 Overview

Findings

- A key recommendation of the Parer Review was removal of ETEF and BPA arrangements in NSW and Queensland irrespective of whether retail price caps are removed. This reform is now in train with the recent announcement of the NSW state government to remove ETEF by 2010 and the decision by Queensland to sell its energy retailing businesses.
- We believe these developments to remove the effects of ETEF and LEP on contracting markets are positive.

8.2 Public ownership

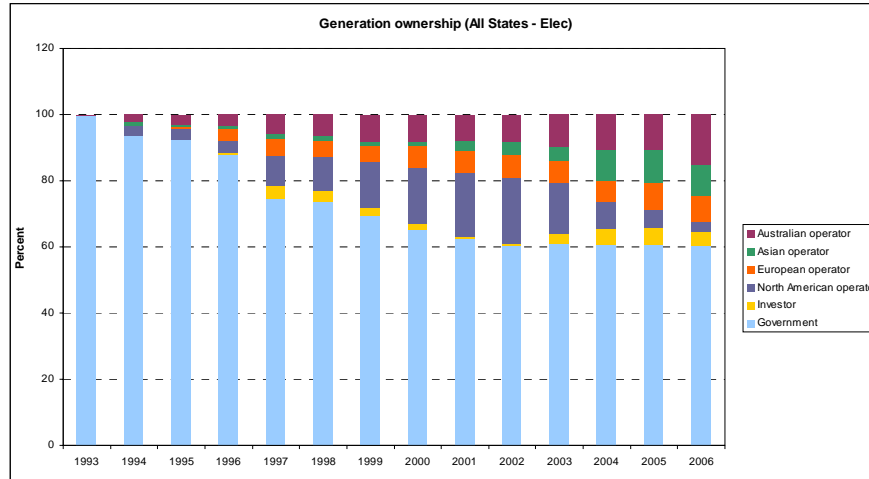
8.2.1 Current state

8.2.1.1 Generation

Figure 49 shows the ownership history of grid connected generation capacity in Australia. In particular, it shows that:

- in 1993 government owned almost all grid connected generation capacity across Australia;
- by 1997 government ownership had fallen to 75 per cent and by 2002 to 60 per cent; and
- since 1997 the degree of private involvement in electricity generation has broadly stabilised.

Figures 49
Changes in the Ownership of Electricity Generation by Type of Owner



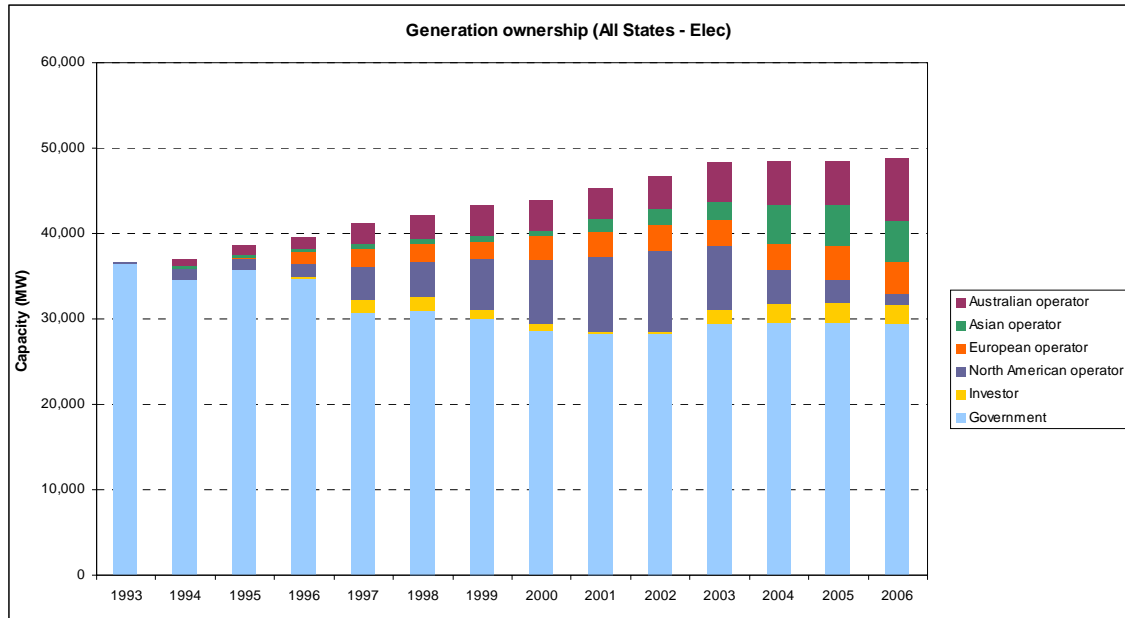
Source: KPMG Analysis

The trend is similar for the NEM jurisdictions only; however, the level of private ownership is more pronounced (i.e. in 2002 government ownership in the NEM fell to about 55 per cent and has since broadly stabilised).

Figure 2 displays the same information as above based on installed capacity. It shows, for example, that:

- In 1993 government owned grid connected generation capacity of 36,000 MW across Australia;
- By 1997 government ownership had fallen to almost 31,000 MW and by 2002 to 28,000 MW; and
- Since that time government owned generation capacity has increased to almost 30,000 MW.

Figures 50
Changes in the Ownership of Electricity Generation by Type of Owner



Source: KPMG Analysis

8.2.1.2 Energy retailing

The changes in retail ‘ownership’ in the electricity and gas sectors by the type of owner focuses on who ‘owns’ the customers in an incumbent sense and therefore shows the proportion of customers whose local retailer is government or privately owned.

Table 5
Electricity Retail Customer Ownership

	1993	1996	1999	2002	2005
Government ownership	100%	75%	75%	66%	67%
Private ownership	0%	25%	25%	34%	33%

Source: KPMG Analysis

Table 5 shows the ownership history of retail electricity customers. In particular, it shows that:

- In 1993 government owned 100 per cent of electricity retail customers across Australia;
- By 1997 government ownership had fallen to 75 per cent of the retail market, and by 2002 it was down to 66 per cent; and
- Since then the level of government ownership has stabilised at around 66 per cent, although it will soon fall significantly with the sale of Sun Retail and Powerdirect in Queensland.

8.2.2 Sale of retailing assets in Queensland

On 26 April 2006, the Queensland government announced its intention to sell off its gas and electricity retail businesses. The electricity retail business includes both franchise and contestable customers in Sun Retail, a wholly owned subsidiary of Energex Ltd.

The sale of Sun Retail will first involve splitting of its customer base into two parts; the first part will house two thirds of the current customer base and remain within the Sun Retail entity. The second part will involve the sale (at a later date) of the remaining customer base, which will be housed in a separate, as yet not named business.

8.2.3 Proposals to transfer electricity price risk to the private sector

The NSW state government has considered proposals to transfer, inter alia, the energy price risk to the private sector in recent years.

In May 2004, the NSW Treasury released a proposal that would transfer the financial risk management activities in relation to NEM from government owned generators and retailers to the private sector. Under that proposal, generators and retailers would sell to the private sector the trading rights associated with their generation or retail customer base for a fixed fee, which would be agreed up front and cover a set period i.e. 5 years.

Government owned retailers and generators would not be obliged to cover any losses incurred by the private sector traders. The aim of the proposal is to eliminate as much market risk as possible from state owned generators and retailers, while still maintaining competition and customer service in the electricity market.

Future policy initiatives may develop along similar lines and, if implemented, have the effect of transferring market risk to the private sector and ultimately the financial markets. This development would be positive for liquidity as this form of policy response may provide the catalyst for the emergence of additional vertically integrated energy groups.

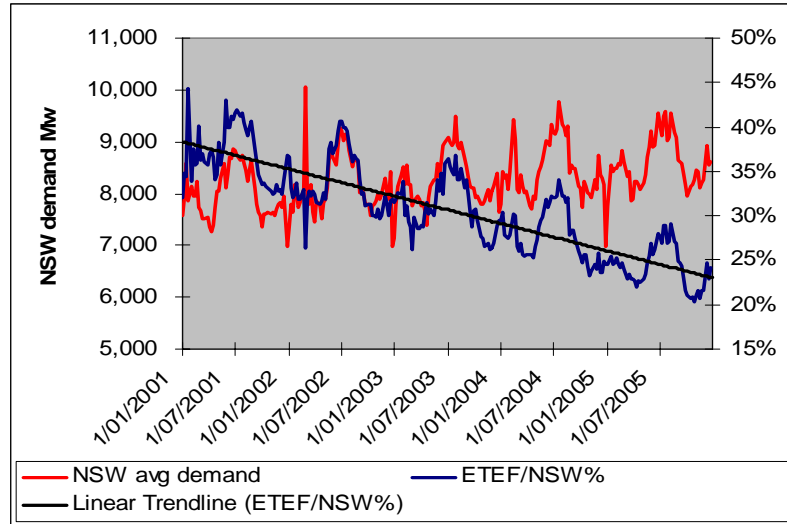
8.3 Financial arrangements to manage wholesale price risk

8.3.1 ETEF

In January 2001, the NSW Government commenced operation of the Electricity Tariff Equalisation Fund (“ETEF”) to reduce the market risk faced by government owned retail suppliers of electricity. The ETEF is designed to offer price protection to non-contestable retail customers (who purchase less than 160 MWh per annum), while ensuring that government owned suppliers are not exposed to unacceptable financial risk.

Figure 51 compares the percentage of the NSW load that is effectively hedged under the ETEF arrangement and does not form part of the available liquidity in the contracting market.

Figures 51
ETEF as a Percentage of NSW Load



Source: NSW Treasury

ETEF does reduce potential market liquidity in the NSW region. In the 2004/ 05 financial year ETEF accounted for approximately 24 per cent of the NSW load, equivalent to 17,673 GWh.

In 2002, the Parer Review noted:

“some [financial] arrangements [such as ETEF in NSW] set in place by governments that own both generators and retailers see huge liquidity taken from the market”.

The New South Wales Government recently announced the abolition of ETEF from 2010 with transitional arrangements from 2008. Arrangements for phasing out ETEF have not been made public however the effect of this policy announcement is likely to have some influence on the contracting market in NSW prior to 2008.

8.3.2 LEP

Long-term Energy Procurement (“LEP”) arrangement established by the Queensland government replaced the Benchmark Pricing Agreement scheme previously in place and covers the franchise customer load.

Under this arrangement, state retailers are compensated for the price risk they experience in supplying franchise customers that is in excess of what other retailers are experiencing. The government determines this excess component by benchmarking the contracts purchased by the retailers supplying franchise load against a range of publicly available and retailer-specific data.

Hence retailers are still required to manage the remaining price risk via the use of derivatives or other similar arrangements.

In this regard LEP provide an incentive for retailers to hedge their load.

LEP scheme has been removed in conjunction with the sale of the retailing businesses. As in the case of ETEF, the removal of LEP and sale of retail assets will contribute liquidity to the financial markets over time.

8.4 Retail price caps

The energy market varies by jurisdiction both in the degree to which they regulate wholesale prices, retail prices or both. In short:

- NSW uses wholesale electricity price regulation (via ETEF) for loads to customers who have not chosen an alternative supplier²⁴
- Queensland is expected to continue to use wholesale electricity price regulation (via LEP) for loads which will not be subject to full retail contestability²⁵
- All jurisdictions use retail price regulation in their electricity markets for small (primarily domestic) customers.
- In broad terms, retail price regulation affects approximately 89% of electricity customers and 29% of demand.

In some instances such as ETEF these retail price caps act as hedges and it might be reasonable to assume that contracting activity would increase if these retail price caps were removed. In addition, the customers and load for which retail price caps are in place are typically also the load that contributes disproportionately to peak demand and therefore the cost of meeting that demand. Hence this also might impact on the amount of trading required to hedge this load.

²⁴ The Electricity Tariff Equalisation Fund seeks to manage electricity market price risk between the government owned generators and retailers in NSW.

²⁵ Queensland has in the past used Long-term Energy Procurement contracts to manage electricity market price risk.

9 Credit risk and prudential framework

9.1 Summary

Findings

- The cost of credit support does not have a major bearing on the level of profitability of the sector although the cost is disproportionately higher for capital constrained newer entrants. In our view, access to capital rather than the cost of credit support under the existing prudential framework is the more substantive barrier to entry for new entrants.
- The separation of spot and forward markets in calculating the level of credit support provided to NEMMCO leads to an inefficient use of participants' economic credit capital. This inefficiency arises because there is no effective mechanism to facilitate the set off of hedge positions with settlement exposures on underlying spot market transactions leading to the circular cash flows occurring between the spot and forward markets.
- The exposure to credit default risk on bilateral contracts can exceed the spot settlement risk given their duration and effect of changes in the level of spot prices over time.
- Overseas energy markets have evolved towards integrating wholesale spot and forward markets under a common clearing system to reduce settlement risks and promote more efficient use of economic credit capital. The transfer of ownership of state owned energy assets to the private sector will lead to concentration of credit default risk resulting from horizontally integrated energy retailing businesses operating across the NEM and is likely to generate significant focus in the near-term.
- NEMMCO and the SFE have submitted proposals to the Australian Energy Market Commission ("AEMC") seeking amendment to the National Electricity Rules ("Rules") on Settlement Reallocations. The SFE proposal or a variant of the proposal resulting from the current consultation process, if codified in the Rules, will reduce the level and cost of credit support without compromising the integrity of the prudential framework. Importantly, the proposal is an important first step towards facilitating the integration of spot and exchange-traded forward markets, promoting the establishment of a common clearing system under a single entity as a logical development of the NEM in line with international precedents in electricity markets.

Recommendations

- We believe the SFE proposal is a positive initiative providing participants with an efficient mechanism to reduce the cost of credit support.
- A full assessment of the benefits of establishing a common clearing system for the electricity market is warranted for the NEM. As noted in Table 9, overseas energy markets have evolved towards integrating wholesale spot and forward markets under a common clearing system to reduce settlement risks and promote more efficient use of economic credit capital.

9.2 Management of credit risk

9.2.1 Source of credit risk in energy markets

Participants in the Australian energy market are exposed to credit default and settlement risks on spot and forward transactions.

In broad terms:

- *Credit default risk* is the risk of loss associated with a market participant experiencing a pejorative change in their credit status that could potentially lead to that market participant being unable to fulfil their payment obligations as and when they fall due.
- *Settlement risk* is the risk of non-payment of a financial obligation by a market participant to a transaction on the date of settlement.

Systemic default risk relates to dramatic changes in the economic environment or contagion effect of default of a market participant causing instability in the NEM affecting multiple participants.

This section briefly outlines:

- the mechanisms established for the NEM and forward markets to mitigate the pricing of credit default risk in wholesale spot and forward contracting markets;
- implications of consolidation of retailing businesses in the NEM on concentration of credit risk on the Retailer of Last Resort (“ROLR”) scheme;
- recommendations to improve the overall efficiency of the use of economic credit capital to reduce the potential impact of settlement risk in the NEM and promote a common clearing system.

9.2.2 Wholesale spot market

9.2.2.1 Gross pool market design and spot price volatility

The NEM is a gross pool market design whereby all electricity generated is sold into the spot market and retailers are required to purchase electricity from the pool to meet demand from their customers. Transactions are valued and settled at the potentially volatile regional reference price.

The financial settlement process for the NEM involves NEMMCO collecting all money due for electricity purchased from the pool from market customers, and paying generators for the electricity they produce as a result of dispatch instructions. The financial liability of all market participants is calculated on a daily basis and settlement occurs up to 5 weeks after the liability accrues. As noted in section 4, the NEM exhibits extreme price movements reflecting the physical characteristics of electricity. The high level of VOLL set at \$10,000 MWh accentuates settlement risk given the timing difference between the billing period and actual payment.

9.2.2.2 Prudential framework

The risk of short payment from default of a participant is shared proportionally market participants due payments in that billing cycle.

The National Electricity Rules (“Rules”) includes market rules governing the creditworthiness of energy retailers to manage settlement risk in the NEM and ultimately systemic risk arising from the failure of a retailer. These rules comprise the prudential framework to ensure that generators have confidence in providing credit to the pool and credit default risk is not factored into the determination of spot prices through the bidding process.

Under the prudential framework, NEMMCO requires the lodgement of unconditional financial guarantees from accredited financial institutions and security deposits against an established maximum credit limit (“MCL”) for each market customer to minimise the probability of any shortfall in payment collected.

MCL’s are calculated for each participant by NEMMCO on the basis of the ‘reasonable worst estimate’ over a 42-day trading period in the NEM. The 42-day trading period is defined as the 7 day billing period, the 28-days for final billing and the 7-day reaction time and the MCL is set to a probability level such that it would not be exceeded more than once in 48 months.

NEMCO also sets a trading limit for every market participant which acts as a “... trigger for action by NEMMCO...”²⁶ by indicating that a participant is close to reaching its credit support limits. Trading limits are set at either 84 per cent of the MCL or where a participant has agreed to participate in the Reduced Maximum Credit Limit (RMCL) option, 75 per cent of RMCL.

²⁶ Australia’s National Electricity Market-Trading Arrangements in the NEM, Executive Briefing, 2004, Pg 18

The RMCL option allows a participant to reduce their credit support by 33 per cent and correspondingly the cost of credit support.

Reallocations which allows for netting of participants' spot and hedge markets, provides participants with another opportunity to reduce the amount (and cost of) credit support required. Increased adoption of these facilities also significantly reduces the amount of capital contingency required to indemnify the NEM against unexpected loss.

Participants have not used either mechanism to any large degree to mitigate the cost of credit support.²⁷

9.2.3 Forward markets

9.2.3.1 Over-the-counter markets

Management of credit risk in the contract market is the responsibility of individual participants.

All forward transactions contain credit default risk due to the impact of changes in the underlying energy or commodity price on the counterparty's ability to settle its obligations as and when they fall due. Contract performance increase as time passes with longer-dated forward contracts exposed to greater counterparty risk than for those with a shorter duration.

Participants in the NEM usually establish counterparty credit limits as the primary mechanisms to manage credit default and settlement risks. While bilateral hedging contracts are typically dealt under ISDA documentation to facilitate netting in the event of default, use of margining and other forms of collateralisation are not as common in comparison to financial markets and the futures market in particular.

Importantly, credit default risk cannot be eliminated from the contract market and if systemic will be factored into the behaviour of the market participants through smaller limit positions, duration of hedges and distorted prices.

There is little empirical evidence that credit default risk is priced within the OTC and bilateral markets. While credit default swaps²⁸ can provide a useful reference to quantify the margin for counterparty risk, most participants have yet to adopt a quantitative approach and include credit risk in the pricing and valuation of energy derivatives.

The impending sale of the Queensland retailing businesses has provided a sharper focus on credit risk in the contract market in terms of the value of the state government guarantee and the differential credit rating between government owned merchant businesses and private sector energy retailers.

²⁷ NEMMCO submission to ERIG

²⁸ Credit default swap is a refined form of a traditional financial guarantee, with the difference that a credit swap need not be limited to compensation upon an actual default but might even cover events such as downgrading, apprehended default etc. Both credit default swaps and financial guarantees are credit derivatives.

9.2.3.2 Exchange traded markets: SFE Electricity Futures Market

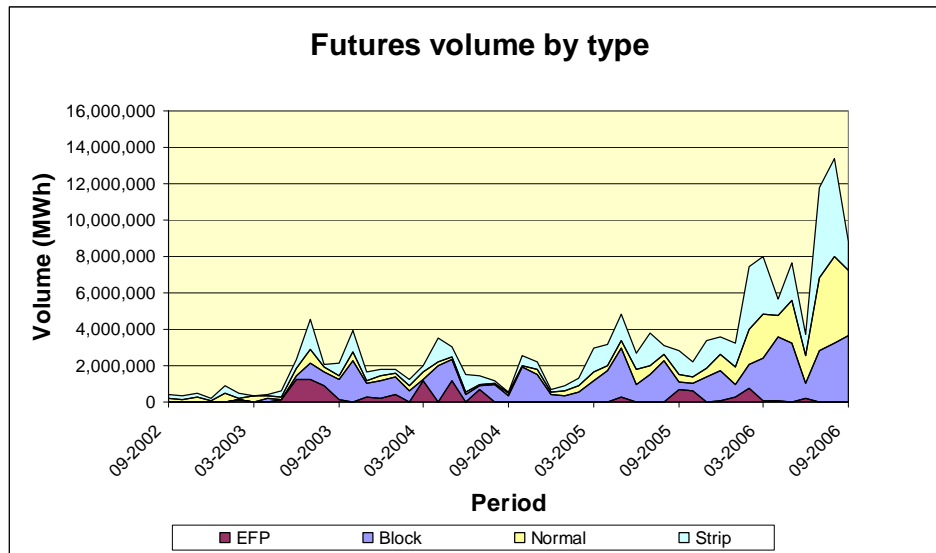
The SFE provides a mechanism for participants in the NEM to mitigate credit risk by transacting contract positions. Futures exchanges are characterised by the novation of contracts where the SFE Clearing acts as counterparty for every trade (i.e. is a buyer for every futures contract sold and a seller for every futures contract bought) and the use of credit mitigation practices to re-distribute credit risk between counterparties which may be 'credit-challenged' on a bilateral basis.

The process of novation on the SFE provides a number of benefits including surety of payment, margin netting, risk management and liquidity²⁹. Transacting futures contracts on the SFE enables energy traders to deal with any market participant without the need to assess their credit worthiness as in the case of the bilateral contracts market where modifying or close-out their original transaction must involve the original counterparty. Eliminating credit assessment from the contracting decision is no different to energy trading in the wholesale spot market, promoting in turn liquidity and price transparency in the forward market.

Figure 52 highlights the increasing use of block trade facility by market participants in the NEM as a mechanism to manage counterparty credit risks.

²⁹ The SFE Clearing (SFECC) remains liable to perform against all contracts to which it is a party, even if either the buyer or seller fails to fulfil its obligations. SFECC therefore effectively guarantees performance of all contracts. The SFECC imposes comprehensive entry criteria on its participants, including strict financial requirements. It ensures adequate capital, guarantees and operational safeguards are in place at all times and it continually monitors these to enable this to happen and ensure the continued financial integrity of both the central counterparty clearing process and the market.

Figure 52
Analysis of SFE / d-cypha trades: 2002 -2006



Source: SFE/ d-cyphaTrade

As noted in section 4.7.2.2 the use of the block trade facility is used to manage credit risk between contracting parties in the NEM reflecting the advantages of the futures market over OTC contracting practices. Market participants in the NEM are able to convert OTC positions from bilateral contracting into futures equivalent contracts transacted through the SFE to overcome restrictions on available credit limits to accommodate these trades. The announced sale of the Queensland government’s interests in its energy retailing businesses may have contributed to the increased use of block trades observed during 2006.

9.3 Credit support

9.3.1 Availability and financial impact of credit support to market participants

Economic credit capital to mitigate credit default risk in the NEM is held in the form of financial guarantees. Table 6 (following page) summarises the extent and source of credit support provided to NEMMCO by market participants.

At one level, the overall financial cost is not significant in the scheme of the profitability of the industry. However, the financial impact to energy retailers varies between investment grade integrated energy businesses and newer retailers in the early stages of growth strategies facing higher credit financing costs and lower profitability.

This disparity is a natural consequence of the credit market pricing for risk: however it does provide the financial incentive for capital constrained participants to use credit mitigation techniques to reduce cost of credit support.

Significantly, 64 per cent of financial guarantees are provided by state-owned treasury corporations reflecting the extent of public ownership of retailing businesses in the NEM. Currently, \$347 million in financial guarantees are provided by the Queensland Treasury Corporation and relate to the energy retailing businesses in the process of being sold.

**Table 6
Credit Support Provided to NEMMCO – September 2006**

Credit support provided to NEMMCO	\$1.579 Billion
Form of credit support	Bank or State Treasury Corporations guarantees
	\$M
Bank guarantees	572 36%
State Treasury Corporations:	
- Queensland	347 22%
- Other	660
	1,007 64%
	1,579
Estimated annual cost using range 25 to 100bp	\$4 – \$16 M
Aggregate reported segment results for Retailing businesses for major retailers	\$1.8 Billion
Estimated cost as a % of operating profits	Less than 0.5%

Source: KPMG Analysis

The transfer of government-owned retailing businesses or the energy price risk embedded in those business to the private sector over time will require in excess of \$1 billion of additional credit support to be financed by the banking system.

Submissions to ERIG identified the quantum of financial guarantee facilities available to the energy sector and individual names as a potential issue for retailer participants. This issue is particularly relevant in the context of full privatisation of the NEM over time.

There is no indication at this stage that credit financiers in the banking and insurance³⁰ sectors are unable or unwilling to accommodate the provision of additional credit support facilities of up to \$1 billion in the event of full privatisation of the NEM given existing level of direct

³⁰ Insurance groups have the potential to provide credit support but have not been accessed to date

lending to the sector³¹ and the tendency of higher rated energy groups to rely on capital markets for long-term funding through the disintermediation process.

Acceleration of the transfer of ownership of retailing businesses to the private sector (either through sale, privatisation or transfer of financial risk as outlined in section 7) will lead to further concentration of credit risk in the NEM involving either existing integrated energy groups (in the absence of competition issues) or the possible emergence of another major competitor.

Potential enhancements recommended in this study to shorten the settlement cycle and integrate spot and forward settlements will increase credit financing capacity to accommodate the transfer of state governments' interest in retailing businesses to the private sector.

9.3.2 Pricing of credit support

The financial strength of energy retailers in the NEM varies from highly rated state government owned corporations to unrated new entrants in energy retailing. Relative creditworthiness is typically measured in terms of long-term senior-unsecured issuer ratings as assigned by Moody's or Standard & Poor's. Agency ratings are a qualitative and ordinal measure of creditworthiness, which is defined in quite general terms³².

Table 7 compares the indicative long term ratings of market participants with the estimated cost of financial guarantees using industry standard credit pricing methodology.³³

³¹ Credit portfolios of financial institutions include direct lending and financial guarantees as complementary lending products assessed under the same credit equivalent limit structure.

³² For instance, Standard & Poors defines its ratings scale as follows. Obligations rated AAA are judged to be of the highest quality, with minimal credit risk. Obligations rated AA are judged to be of high quality and are subject to very low credit risk. Obligations rated A are considered upper-medium grade and are subject to low credit risk. Obligations rated BBB are subject to moderate credit risk. They are considered medium-grade and as such may possess certain speculative characteristics. Obligations rated BB are judged to have speculative elements and are subject to substantial credit risk. Obligations rated B are considered speculative and are subject to high credit risk. Obligations rated less than B are judged to be of poor standing and are subject to very high credit risk.

³³ The credit pricing methodology takes account of cumulative default probabilities (DP) and loss given default (LGD) analysis.

**Table 7
Cost of Credit Support by Long Term Issuer Credit Rating**

	Long Term Credit Rating				
	AAA	AA	A	BBB	Sub-investment Grade (BB-B ¹)
Market participant					
Government owned corporations					
Major integrated energy groups					
Other participants and new entrant retailers					
Indicative mid range cost of credit support (bps/ p.a)	25	25	50	100	400-1700

Source: NEMMCO submission, KPMG analysis

The analysis highlights the broad distribution of creditworthiness of market participants across the NEM and the importance of the prudential framework in ensuring that credit risk is excluded from the pricing of electricity in the wholesale spot market.

The cost of credit support increases significantly below investment grade - most of the vertically integrated energy businesses have investment grade (BBB or higher). As noted in this section, the pricing of credit support does have a disproportionate impact on the financial operations of newer retailers compared to larger government owned or integrated energy businesses however this is a reflection of the pricing of risk in the credit market rather than a lack of equity in the design and operation of the prudential framework.

As a consequence, newer entrants tend to rely on equity capital or financing facilities provided by major shareholders, typically listed investors in infrastructure assets, to finance their operations and meet prudential requirements³⁴. Shortening the settlement cycle will reduce the level of credit support provided to NEMMCO by reducing the MCL however this development simply substitutes contingent off balance sheet capital for on-balance sheet working capital³⁵.

9.4 Mechanisms to set-off financial arrangements in electricity markets

9.4.1 Settlement re-allocations

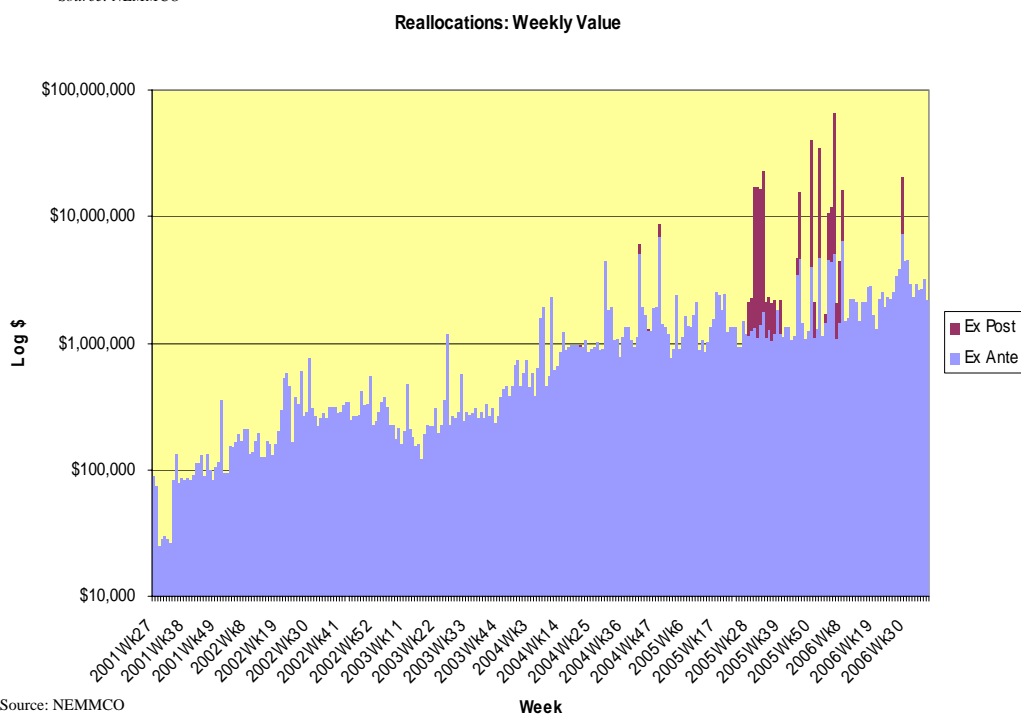
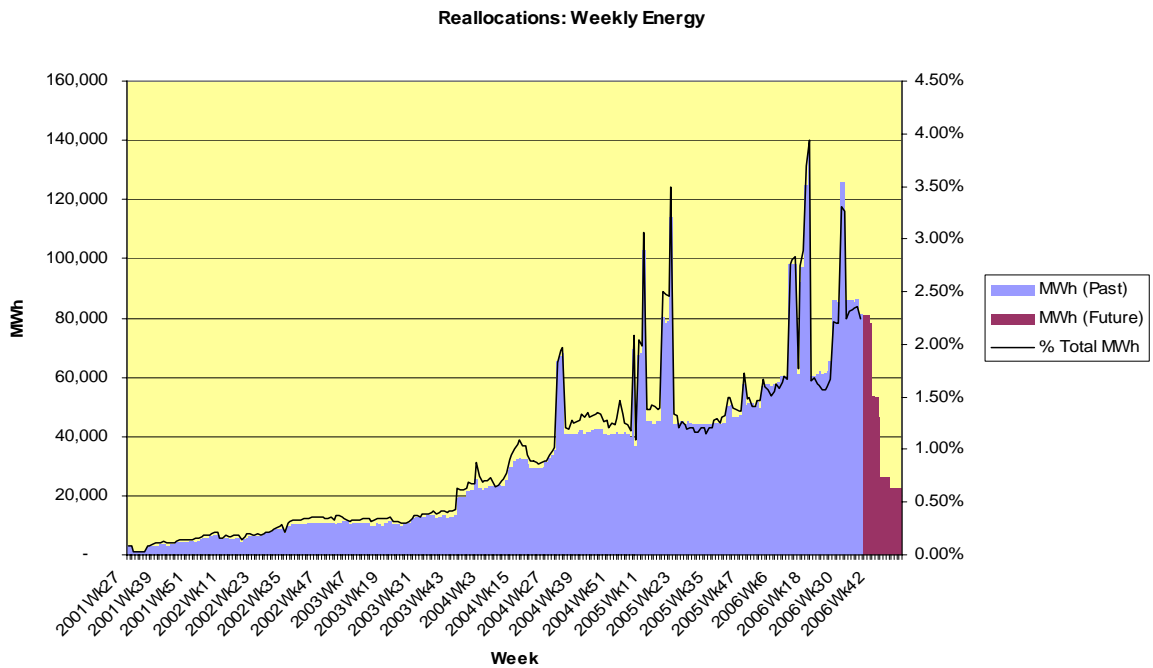
Participants are able to offset their positions associated with financial contracts with spot market obligations via NEMMCO to reduce the amount and cost of credit support. Referred to as

³⁴ Infratil Limited is a major investor in Victorian Electricity and provides financial accommodation placed on deposit with NEMMCO as security for electricity purchases. Backcock & Brown is a substantial shareholder in Jackgreen Limited.

³⁵ The cash flow affects would depend on customer billing arrangements and terms negotiated for derivative contracts. In general, retailers would be expected to have increased borrowings with the cash flow benefits passed through to generators.

Settlement Re-allocations, this mechanism has not been used extensively to date. Tables 53 and 54 graph the utilisation of settlement reallocations by MWh and settlement value since 2002 compared to total energy purchases.

Figures 53 and 54
Settlement Reallocations by Energy (MWh) and Value of Energy (\$)



Historically, re-allocations account for less than 2 per cent of wholesale market settlements and do not appear to represent an efficient mechanism to manage credit risk except in the case of vertically integrated energy groups and smaller retailers. Bilateral hedging transactions between generators and retailers are largely outside the re-allocation process.

A study of the settlement re-allocation process commissioned by NEMMCO in 2005³⁶ attributed the low utilisation to:

- confidentiality concerns over centralisation of financial information (with NEMMCO);
- lack of a financial incentive for generators to participate;
- ready access to state treasury arrangements for some retailers;
- lack of comprehension of the significant consequences of a participant default; and
- the operation of government equalisation funds (e.g. ETEF).

A concern raised by participants in using the current settlement re-allocation facility is the residual exposure faced by generators in the event of insolvency by retailers to clawback under preferential payments provisions of the Corporations Act in periods of high pool prices.

9.4.2 Alternative proposals to reduce credit support

Table 8 summarises details of proposals submitted to the AEMC on the proposed rule changes to the settlement re-allocation process.

The SFE proposal is designed to use the credit mitigation framework underpinning futures trading as the mechanism to reduce the circular settlement of cash flows and as a residual benefit also address industry concerns over perceived financial and regulatory risks that have provided a disincentive to generators to use the settlement re-allocation process.

We are supportive of this proposal which, if endorsed by the AEMC and codified into the National Electricity Rules, will reduce the level and cost of credit support required without compromising the integrity of the prudential framework. Importantly, the proposal is an important first step towards facilitating the integration of spot and exchange-traded forward markets promoting the establishment of a common clearing system under a single entity as a logical development of the NEM in line with international precedents in electricity markets.

As noted in Table 9, overseas energy markets have evolved towards integrating wholesale spot and forward markets under a common clearing system to reduce settlement risks and promote more efficient use of economic credit capital.

We believe a full assessment of the benefits of establishing a common clearing system for the electricity market is warranted.

³⁶ NEMMCO Prudential Processes in the National Electricity Market, Deloitte, July 2005

**Table 8
Summary of Proposals to AEMC on Amendment to Settlement Re-Allocation Process**

	Current	NEMMCO Proposal	ASX/SFE Proposal
Features	<ul style="list-style-type: none"> • Participants can offset cash flows associated with spot market obligations* 	<ul style="list-style-type: none"> • Participants are able to offset cash flows associated with derivatives & spot market obligations • Encourage the increased use of reallocation contracts 	<ul style="list-style-type: none"> • Futures contracts can be offset against a participant's financial contracts & spot market obligations
Benefits for NEM participants	<ul style="list-style-type: none"> • Ex ante reallocations reduces credit support requirements • Takes into account all pricing periods over the life of the contract • Reduces liquidity risk for participants during peak periods i.e. avoid cash settlement 	<ul style="list-style-type: none"> • Ability to offset derivative positions against spot market transactions • Participants can further reduce credit requirements 	<ul style="list-style-type: none"> • Exposure is limited to only one business day • Futures contract is guaranteed by the exchange i.e. is much firmer compared to reallocations • Easy to enter and exit futures contracts • Has no credit risk weighting under Basel 2
Risks of participation & issues to be addressed	<ul style="list-style-type: none"> • Non firmness of reallocations, NEMMCO can terminate reallocation if one party defaults • Concentration risk, scheme limited to generators & retailers, • Difficulty in closing out reallocation contracts, has to be with participant in same region • Derivative position of parties to a reallocation are not recognised • Ex-ante reallocations are outside NEMMCO's prudential process 	<ul style="list-style-type: none"> • NEMMCO is solely responsible for determining what is an acceptable re-allocation • Credit support may be unable to cover default events during peak pricing periods • Doesn't cover compensation aspects for losses suffered if a party to a reallocation defaults • Reallocations attracts credit risk weightings under Basel 2 	<ul style="list-style-type: none"> • Requirement for margins which can require top up on a daily basis • Futures prices does not include spot prices that occurs between 5:10pm and the next business day

Source: KPMG Analysis of submissions to ERIG and AMEC

**Table 9
Settlement and Clearing Systems for Spot and Forward Energy Markets**

	NEM	Nord Pool	UK Market	PJM
Single entity responsible for operation of physical market	✓	1	✓	✓
Single entity responsible for operation of physical & financial markets including clearing				
Entity operating financial electricity market and related clearing independent of market operations		✓	✓	✓
Electricity contracts traded on multiple financial electricity markets (need a tick to the right for NEM- we have futures, OTC through brokers etc)	✓	✓	✓	✓

Source: KPMG Analysis

Note 1 - Responsibility lies with transmission companies in relevant regions of the Nord Pool.

9.4.3 Nord Pool

Norwegian electricity market was deregulated in 1992. Nord Pool ASA established in 1993 and started trading in Norwegian financial spot electricity market. It subsequently expanded to other markets including Sweden and Denmark and in 2002 created three companies:

- Nord Spot (owned by all electricity transmission companies in pool and Nord Pool ASA)
- Nord Pool Financial Market a wholly owned company which was licensed as an exchange for commodity derivatives
- Nord Pool Clearing a wholly owned company which was licensed as a clearing house for commodity derivatives (including bilateral and OTC).

Electricity contracts priced off the Nord pool are also traded on the International Commodity Exchange.

9.4.4 England and Wales Electricity Pool

In 1990, electricity Pool of England and Wales created, which was responsible for operating the physical electricity market in England and Wales. However in March 2001, the new electricity trading arrangement came into effect. Changes include the restructure of the physical electricity pool into a net pool and the appointment of Elexon to manage it i.e. responsible for the balancing and related settlement aspects of the electricity market

A related financial electricity markets (including spot and futures) has been developed across a number of exchanges including AP Power UK exchange and the Intercontinental Exchange. A number of parties which are either part of the exchange or independent of it are responsible for clearing all transactions in these exchanges.

9.4.5 PJM

PJM Interconnection LLP was formed in 1993 and is currently responsible for the operation of physical electricity markets in Delaware, Illinois, Maryland, New Jersey, Ohio, Pennsylvania, Virginia, West Virginia and the District of Columbia. It acts as a balancing agent in the respective electricity markets. A financial electricity market has been developed by various exchanges including NYMEX and the International Commodities Exchange where contracts related off the PJM spot pool price are traded. Both exchanges also act as clearing agents.

9.5 Reducing the settlement period in the NEM

The level of credit support required by participants under the prudential framework is attributable to the length of the 35-day accrual period based on 7 day billing period and the 28 calendar days for final billing prior to settlement.

Table 10 compares the billing and settlement periods in the NEM with other energy markets. The 35-day accrual period is comparable to other markets however the level of exposure is magnified by the gross pool design of the NEM compared to balancing markets of the NordPool and UK market.

Shortening the accrual period reduces the level of settlement and credit default risk in the NEM and provides an alternate policy mechanism to the Reduced Maximum Credit Limit ("RMCL") facility currently available.

9.5.1 Reduced Maximum Credit Limit

NEMMCO introduced the option of a Reduced Maximum Credit Limit (RMCL) in Jan 2004.

Entities adopting this facility are allowed to lodge a reduced amount of credit support with NEMMCO in exchange for accepting a lower trading limit (set at 75 per cent of the RMCL).

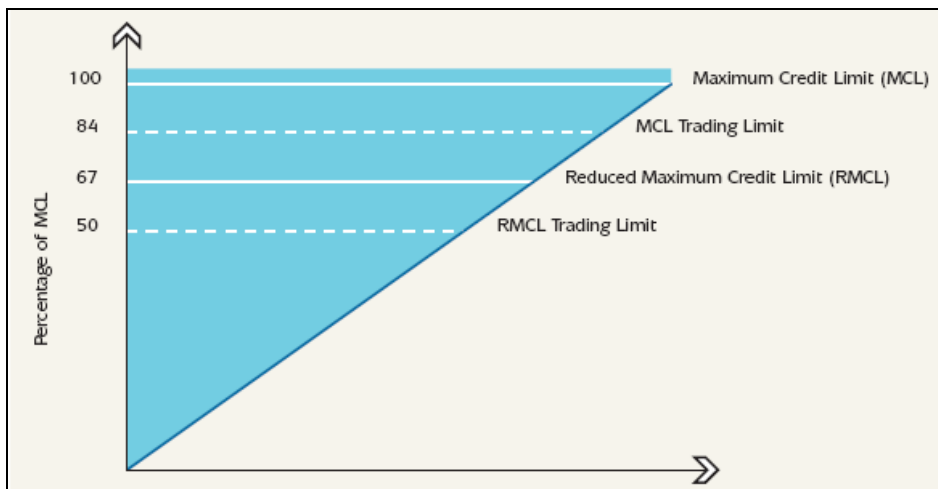
The RMCL is voluntary facility available to participants to reduce their collateral requirements by up to one-third in exchange for agreeing to a reduced trading limit. In the event that a market participant exceeds their trading limit, the same prudential procedures apply under both Maximum Credit Limit ("MCL") calculator and RMCL arrangements.

The practical effect of the RMCL is to encourage early settlement to achieve a comparable outcome to reducing the accrual period.

In determining what the RMCL would be for an entity, the standard Maximum Credit Limit ("MCL") calculator is used except that the trading cycle is reduced from 42 to 28 days. This reduction in the length of the trading cycle led to the RMCL equalling 67 per cent of the market participants' MCL.

Figure 55 provides an illustration of the benefit of the RMCL facility on the level of credit support provided to NEMMCO.

Figure 55
Illustration of the Benefit of the RMCL Facility on the Level of Credit Support



Source: NEMMCO submission to AEMC, Sept 2006

9.5.2 Implications for NEM and financial market settlement processes

Migrating from the voluntary RMCL facility to a mandated reduction in the NEM settlement cycle over time is a desirable policy response to addressing further concentration of credit risk in the NEM.

Reducing the accrual period would increase financing charges for market participants purchasing from the NEM by substituting financial guarantees for increased working capital requirements. The extent of increase would depend on the form of financing adopted however further analysis is required to determine whether the additional financial cost is outweighed by the benefit of a systematic reduction in the settlement risk.

Equally important, a reduction in the settlement period is a significant change that will have wide-reaching implications for NEM participants and will affect end-to-end processes and practices associated with operating in the NEM and related derivative markets. Of particular significance is the potential affect on settlement processes on the contracting market to mitigate cash flow risks so these issues will need to be considered in conjunction with the impact on IT systems, implications for the capture and accuracy of actual customer load data due the reduced timeframes and other processes related to settlements and billing.

The timeframe for implementing any policy change will need to take of these impacts.

9.5.3 Integrated of gas and electricity markets

The further integration of gas and electricity markets over time is a desired and likely outcome for the Australian energy market. In this regard, it is essentially that AEMC deliberations in relation to the operation of gas and electricity markets in Australia consider the need to ensure that settlement and logistical processes are aligned between these markets where possible.

Hence, changes to the settlement and related cycle in the electricity market must be assessed in light of future changes to the broader Australian energy market structure.

**Table 10
Comparison of the Settlement Period and Credit Support Arrangements in NEM to International Energy Markets**

	NEM	Nord Pool	UK	New Zealand
Market Design	• Gross	• Net	• Net	• Gross
Invoicing period	• 7 calendar day billing period	• Daily	• Daily	
Settlement period	• 20 business days	• Next business day	• 29 business days after the settlement day.	• 20 th Calendar day (or next available business day) of the month following the monthly billing period.
Security Requirements	• Cover maximum possible exposure to NEMMCO	• Cover participants collective net purchase position	• Cover equal to or greater than maximum possible exposure	• Acceptable long term credit rating (A- & above) or • Cover participants maximum potential net credit exposure
Calculation Method	<ul style="list-style-type: none"> • Cover maximum possible exposure to NEMMCO • Uses the average future price for a 42 day period and the corresponding volatility • Applied to the load for each counter party • Calculated on a weekly basis 	<ul style="list-style-type: none"> • Net purchase position is based on a participants actual net purchases during the seven most recent days • Calculated daily • For new participants, net purchase position is based on projected net purchases for the next seven days 	<ul style="list-style-type: none"> • Maximum possible exposure is made up of both expected amounts owing for the settlement day and the actual amount owed for the same settlement day. • As you approach the payment day, this measure will represent the actual amount owed • Calculated daily 	<ul style="list-style-type: none"> • Credit exposure is calculated using both current and projected exposures • Latest available trading volumes & prices are used to derive projected exposures • Calculated Weekly
Acceptable Securities	<ul style="list-style-type: none"> • Cash • Guarantees 	<ul style="list-style-type: none"> • Cash • Guarantees. 	<ul style="list-style-type: none"> • Cash • Guarantee (not less than 3 months) 	<ul style="list-style-type: none"> • Cash • Guarantee • Bond • Hedge settlement agreement** • Combination of the above

**:(an agreement between a generator and a purchaser allowing settlement of payments for differences)

Source: NEMMCO, Elexon, Electricity Commission of New Zealand and Nord Pool Web sites
ERIG06-ElectricityTrading1219WRFinal

9.6 Concentrated credit risk and Retailer-of-Last-Resort Scheme

The prudential framework includes mechanisms to deal with the default of a retailer. If an electricity retailer is suspended from participating in the NEM, each of the regions in which the suspended retailer operated in, may nominate a retailer of last resort (“ROLR”). The ROLR will assume the responsibility of providing electricity to the suspended retailer’s customers. This increase in its customer base may mean that the ROLR may have to provide additional credit support to cover its increased exposure to NEMMCO.

The ROLR schemes, put in place at the jurisdictional level to ensure customers continue to be supplied if their chosen retailer financially fails, can be triggered very rapidly when they interact with the NEMMCO market suspension mechanisms. The relevant state authorities (e.g. Essential Services Commission in Victoria) have mandated who the ROLR are and how the customer base will be split. Such an event has the potential to leave the local retailer suddenly under-hedged, possibly at a time of high pool prices. Such an outcome could lead to the default of the local retailer – through no fault of its own. If such a cascading failure was to occur, it is likely that a large number of NEM participants could be impacted.

To date the NEM has been characterised by the absence of significant concentration of energy retailing businesses. The sale of government owned energy retailing businesses in Queensland and potential reform in energy policy in New South Wales and Tasmania are likely to contribute to consolidation with the emergence of a few large retailers operating across the NEM.

The risk of instability in the wholesale spot market is more likely where there is concentrated credit risk however the trend towards vertical integration to manage volatile price risks and proposals before the AMEC to reduce settlement risk provides an important mitigate factors.

Notwithstanding, the ROLR scheme under the prudential framework of the Rules was developed in contemplation of multiple retailers and the active involvement of state governments in the energy sector.

In the event that the Queensland retailing assets are acquired by an incumbent retailer to create a dominant energy businesses operating across the NEM, the operation of the ROFR scheme under the Rules and response timeframe incorporated in the MCL calculation should be reviewed by NEMMCO to ascertain whether the current arrangements adequately deals with concentration risk and the requirement for a national approach to managing this event risk and, in particular, how customers should be re-allocated and the ability of the acquiring or default retailer being able to economically and efficiently hedge the load risks.

9.7 Recommendations

Recommendations

- We believe the SFE proposal is a positive initiative providing participants with an efficient mechanism to reduce the cost of credit support.
- A full assessment of the benefits of establishing a common clearing system for the electricity market is warranted for the NEM. As noted in Table 9, overseas energy markets have evolved towards integrating wholesale spot and forward markets under a common clearing system to reduce settlement risks and promote more efficient use of economic credit capital.

10 Demand side management

10.1 Overview

Findings

- The Parer Review in 2002 made several recommendations to improve the utilisation of demand side management (“DSM”) in the NEM and deliver a range of benefits in energy risk management as well as potentially deferring investment in infrastructure.
- These recommendations covered the introduction of mandated interval meters within 5-10 years (from the date of the Parer report), full retail contestability within 3 years and the implementation of a controversial ‘pays as bid’ process whereby DSM providers are paid an agreed price akin to a capacity payment as opposed to one related to the system marginal price (spot price).
- Since the Parer Review, there has been limited growth in utilisation of DSM which is mainly restricted to large contestable energy users. The mass market has significant potential but is largely untapped. The factors contributing to this current state are varied and include the following.
 - Government intervention through financial arrangements such as ETEF and LEP and price caps.
 - DSM activities are currently difficult to capture and administer in practice leading to higher transaction costs compared to other risk management solutions to manage retail load risks.
 - The lack of a liquid, transparent short-term derivative market makes DSM difficult to value - further dampening the price signals crucial to providing incentives to contestable customers.
 - Retailers are the main beneficiary due to the physical nature of DSM reducing the financial incentive for large contestable customers to provide firm commitments.
 - The non-firm nature of demand side load reduction remains a key issue for retailers reducing the value of DSM as a viable structural hedge of load risks compared to the contracting market or investment in generation assets.
- The recent decisions to abolish ETEF and removal of LEP arrangements in conjunction with the proposed sale of retail businesses in Queensland are positive steps for the NEM with potential benefits for DSM as improved liquidity in the short-term derivative market (particularly the day-ahead and week ahead) will provide the price signals essential for encouraging increased utilisation of DSM.

Recommendations

The Parer Review made a number of recommendations designed to allow utilisation of DSM by participants to evolve through competitive market forces that are still relevant today. These recommendations relate to:

- the removal of price caps to encourage competition in the residential sector and provide the incentive for energy retailers, distributors, end-users and other parties to more effectively utilise DSM capacity and reduce its transaction costs; and
- implementation of interval/smart metering at the residential level.

Facilitation of improved liquidity in the short-term derivatives market and continued growth of the SFE futures market will provide increased price transparency that will assist in valuing DSM and encourage further participation amongst energy users and participants across the NEM.

10.2 Role of DSM in managing electricity price risks

DSM relates to the modification of energy consumption by customers in response to various market events such as physical or weather-induced high demand and price spikes in return for financial incentives provided by an incumbent retailer or other party.

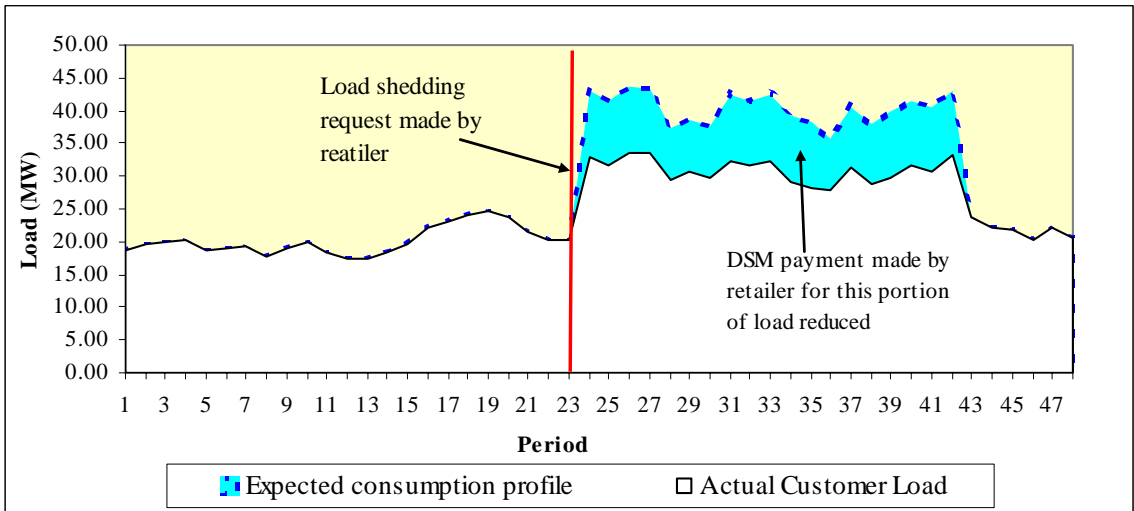
DSM is an important risk mitigation tool for market participants operating in a deregulated energy market providing an alternative to traditional contracting arrangements.

This activity currently involves large contestable end customers with energy-intensive equipment or processes that can be modified or switched on or off at short notice to reduce electricity demand from the grid. The displacement of customer load on the grid by turning to on-site generation is another option available to energy users with generation facilities and also constitutes demand side management as it reduces system demand. This activity is akin to turning on a peaking generator and in essence is an off-market supply side instrument.

The mass-market sector is generally not party to DSM activity. The lack of interval metering prohibits accurate measurement of demand side response by these customers because it is impossible to determine the exact load reduced during a DSM event. The absence of price signals at the consumer level effectively provides insulation against market events and hence DSM opportunities so removes incentives for these energy users to participate.

Figure 56 outlines the general concept of DSM as applied to a generic customer load by an energy retailer.

Figure 56
Assumed Customer Demand Profile vs Actual Customer Load after DSM

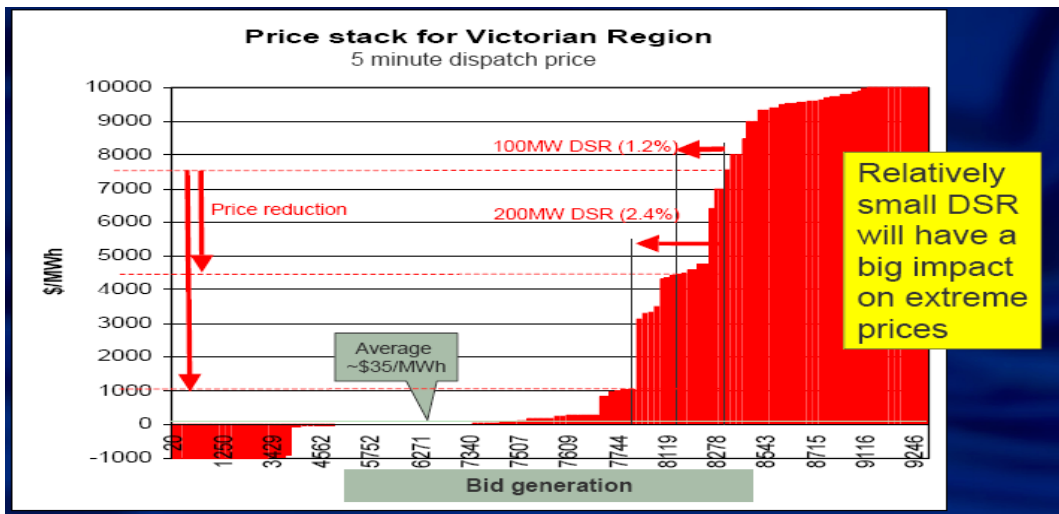


Source: KPMG Analysis

Network businesses also pursue DSM activities by providing incentives to customers who are able to reduce or shift their energy use at times of peak system demand as this may help to defer the need to augment network capacity. Hence, DSM in this capacity results in more efficient network usage and reduced capital expenditure.

Figure 57 below demonstrates that even small amounts of DSM can result in significant spot price reductions when price bids submitted by generators are tightly spaced.

Figure 57
Impact of DSM on Spot Price using Example Generation Price Stack in Victoria



Source: Energy Response

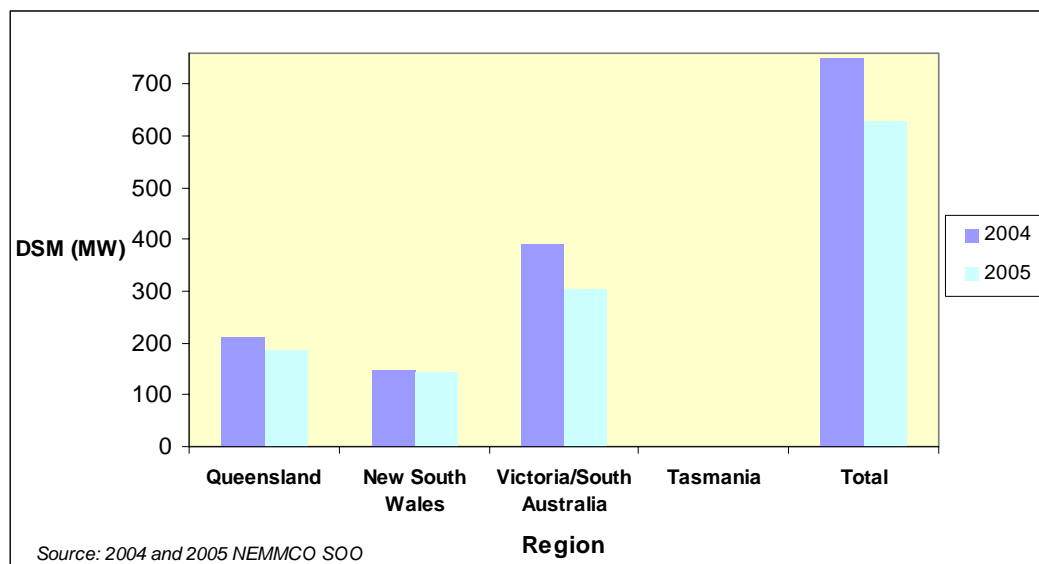
10.3 Level of DSM activity and potential capacity in the NEM

10.3.1 Utilisation of DSM in energy price risk management

At present electricity retailers within the NEM rarely utilise DSM to reduce pool price exposure within their portfolio at times of extreme prices and other market issues. Anecdotal evidence suggests DSM accounts for around 1 per cent of the portfolio hedging arrangements of retailers.

NEMMCO estimates 700MW of DSM capacity is available across the NEM to manage load risk³⁷. Figure 58 analyses this capacity by region and incorporates both committed and non-committed DSM capacity based on NEMMCO's survey of energy retailers and industry bodies.

Figure 58
DSM Capacity in the NEM by Region



The level of non-committed DSP capacity in 2004 and 2005 was 334MW and 330MW respectively. Surprisingly, the level of committed capacity for NSW at approximately 10MW is extremely low and an indication DSM is underutilised in that region.

Energy retailers are the main beneficiaries of DSM activities due to the physical links with their customer portfolio through NEMMCO. Reduction in customer load is directly attributable to the incumbent retailer hence efforts by external parties to engage in DSM activities with these customers is difficult due to the physical nature of the activity.

Financial intermediaries general do not participate in DSM activities and are unlikely to value DSM until it can be delivered in a reasonably firm manner and in the form of a derivative. Further, financial intermediaries are not able to become reallocation entities due to current

³⁷ NEMMCO, 2005 Statement of Opportunities

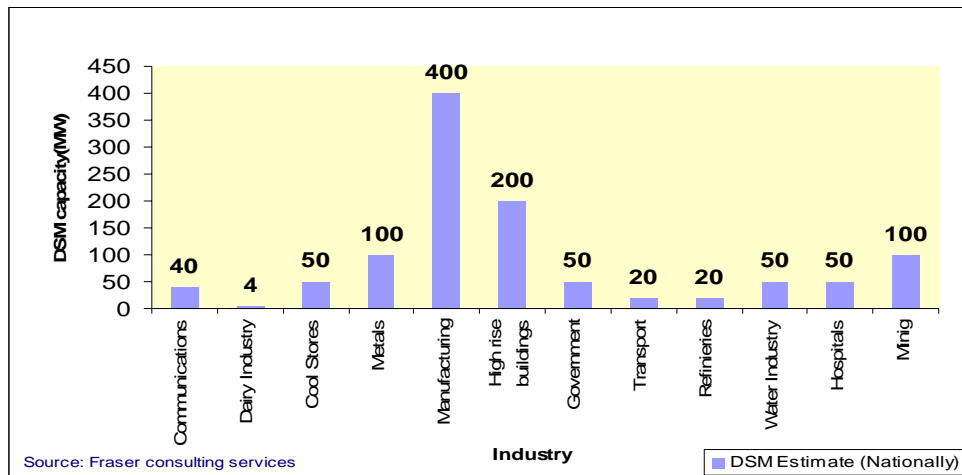
restrictions imposed by NEMMCO. However, a proposed rule change submitted to the AEMC will introduce a new market participant category called a “Reallocator” thereby enabling participation by financial traders.

10.3.2 Potential capacity in the NEM

A conservative estimate of the potential DSM capacity in the NEM is significantly higher than the 700MW reported by NEMMCO rising to approximately 3000MW³⁸ nationally if the residential market participates in DSM activities.

The following chart shows the potential DSM capacity by industry sector (excluding the residential market).

Figure 59
DSM Estimate in MW (Nationally)



Opportunities to provide DSM capacity within these industries include:

Pumps and compressors – Various industrial plants contain pumping devices whose running schedule could be altered to minimise demand at high prices. Examples include sewage treatment and water storage.

Batch processes - Many industrial operations involve batch processes (eg smelters, quarries, manufacturing, wineries etc) that can be rescheduled or reconfigured to avoid peak demand and price periods.

Air-conditioning and cold storage- Air-conditioning and refrigeration installations generally involve cooling a building or storage room to a set temperature at which point the refrigeration system turns off. By controlling this cycle can reduce energy consumption during peak periods.

Backup generation- Many large buildings and operations have backup generation installations that can be run on-demand to reduce energy drawn from the grid.

³⁸ EUAA Demand Side Response in the NEM Case Studies, April 2005

10.4 Factors contributing to low utilisation of DSM

There are a number of contributing factors to the relatively low utilisation of DSM activity in the NEM and constraining further development of capacity to enable retailers and other market participants to manage demand-induced price spikes and promote liquidity in financial trading.

Key factors include the following:

- Retail supply agreements inflexible and do not encourage DSM activities.
- Non-firmness associated with most DSM contracts limits the value of DSM to both parties.
- Energy retailers are the main beneficiaries of DSM yet they generally appear to under-utilise DSM and not pass on the appropriately value of DSM to their customers.
- Inability for financial intermediaries to participate in the DSM market as noted above.
- Difficulty in capturing the value of DSM due to spot price variability.
- Opportunity cost is often too great for energy users to participate in DSM activities due to the risk of catastrophic failure within key business processes.
- Lack of liquidity in the short-term market (day ahead).
- Retail price caps and other mechanisms that suppress price signals to the consumer.
- Lack of interval metering at the residential level limits access to mass market.

10.5 Measuring and capturing the value of DSM

Some of the key issues cited by participants that prevent the benefits of DSM from being measured and the value ultimately captured by potential users of DSM in practice include:

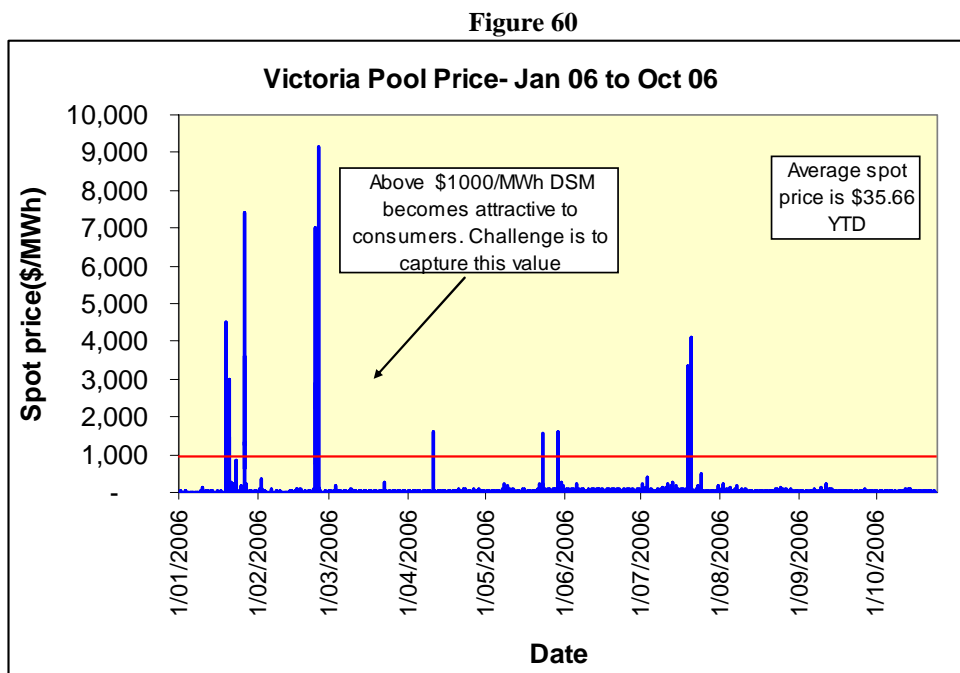
- Variability in actual versus forecast spot prices can result in mistiming of DSM activity that ultimately reduces the financial return and, if systemic, reduces incentive to continue with DSM over-time;
- The ‘free rider effect’ created by parties utilising DSM activity bearing the cost of the DSM which may in turn significantly reduce pool prices across one or more NEM regions to the benefit of the entire market. This argument is often cited as a disincentive to undertake significant DSM activities for some players. However, market forces are highly effective in pricing risk taking activities. DSM will remain viable so long as the financial returns to DSM parties are commensurate with the costs and inconvenience of disruption committing to shedding load;

Aggregators such as Energy Response may assist by managing a DSM portfolio in a more timely and efficient but this will take time. The difficulty in providing firm DSM (i.e. fixed load reduction for a set time frame) limits the effectiveness and consequently the value of DSM. Spot price volatility and hence the logistics around the DSM instruction process can be cumbersome and often result in customers not receiving the expected payout for their DSM efforts;

- Lack of interval metering makes it difficult to measure demand reduction for mass market consumers and small businesses. The introduction of interval metering would allow greater DSM participation at the residential level;
- Illiquidity in the short-term financial market makes it difficult to value DSM activities since there is no transparent market that can be referenced other than the spot market forecast provided by NEMMCO;
- Retail supply agreements are often too inflexible and simplistic and hence not able to appropriately facilitate innovative DSM activities as they often restrict energy users from exploring DSM options outside the agreement;
- Energy retailers that currently have DSM capability do not appear to be adequately utilising this and hence not passing on the appropriate value of DSM to their customers. Anecdotal evidence suggests that some energy retailers offer minimal discounts (e.g. \$1-2/MWh) in return for DSM rights and the potential to participate in profit sharing arrangements. However, it appears that these conditions are tested infrequently in practice and payments made to energy users for DSM events are often not equitable and unfairly weighted for the risk borne;

- The EUAA estimates that the price level that makes DSM attractive is around \$1000/MWh which is very high and unlikely to be realised for extended periods of time in the current market environment. Spot prices in excess of \$1,000 /MWh occurred infrequently across the NEM in 2006 to date.

Figure 60 demonstrates the potential DSM opportunities in VIC from Jan 06 to Oct 06. Note that the spikes are relatively infrequent and of short duration.



Source: KPMG Analysis

Table 11 shows the proportion of spot market revenue attributable to spikes across each NEM region (excluding Tasmania) in 2006. This is an indicator of the quantum of potential pool savings that can be accessed by utilising DSM activity.

Table 11
Proportion of Spot Market Revenue Attributable to Spikes by NEM Region

	QLD	NSW	Snowy	VIC	SA
Revenue Based on Cut-off	\$ 462,125,640	\$ 983,822,427	\$ 3,576,630	\$ 739,873,870	\$ 155,937,116
Total Revenue	\$ 2,430,123,084	\$ 4,631,948,344	\$ 26,730,281	\$ 3,311,125,160	\$ 958,319,025
% of Total Rev	19.02%	21.24%	13.38%	22.35%	16.27%

Source: KPMG Analysis

10.6 Promoting DSM as a market-based solution

10.6.1 The role of aggregators

Executing a DSM strategy is quite cumbersome and time consuming for energy retailers due to the administrative process of negotiation and scheduling process that needs to take place.

Aggregators such as Energy Response provide a market solution by assembling a portfolio of customers that can be offered to energy retailers to achieve their DSM strategy thereby lowering transaction costs. Energy Response were awarded a Reserve contract by NEMMCO to provide 125MW of firm Vic-SA reserve over the summer period in 2005-6 and has sourced a further 780MW of DSM from more than 200 Industrial and Commercial energy consumers. The 125MW reserve contract involved more than 60 customers and over 100 sites in Victoria and South Australia.

The emergence of aggregators is an indicator of the market forces responding to price signals to cost-effectively provide NEMMCO and retailers with an alternative to the contracting market to manage load-related price risks.

10.6.2 Retail innovation and potential to increase DSM activity

Innovative retail strategies and further involvement of energy users in the wholesale market may facilitate further DSM activity and encourage non-traditional participation by financial intermediaries in the DSM market. For example, a large energy user may choose to enter into a pool price pass through agreement and hedge its price exposure utilising energy derivatives or a reallocation agreement rather than choosing a standard retail supply agreement.

This strategy would provide access to a range of risk management products that can be transacted with wholesale market participants including financial intermediaries.

DSM is also possible due to the purely financial nature of the hedge portfolio. That is, any reduction in volume is purely physical and affects the customer's pool price payments to the retailer. However, the financial exposure to hedge counterparties would remain unchanged. Hence, the user can benefit from difference payments from the derivatives transacted in the event of load shedding.

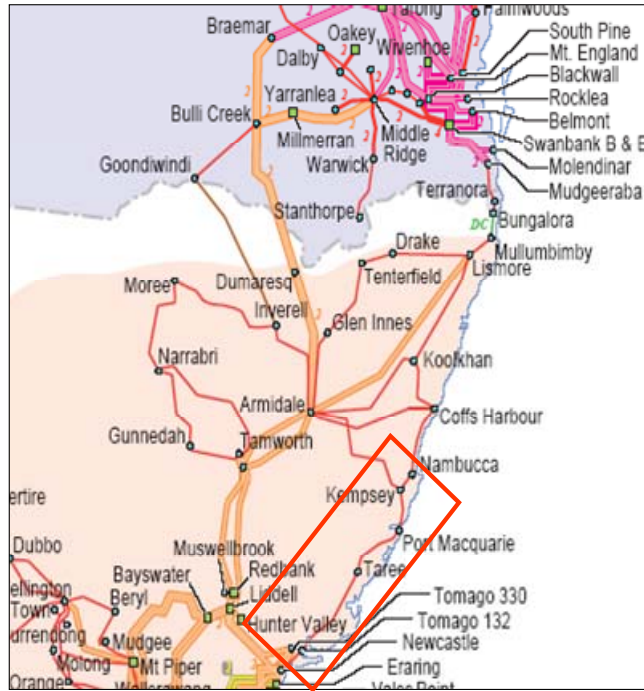
10.6.3 The potential benefits of DSM for financial markets

There a number of potential benefits that DSM can deliver for energy retailers and NEM participants in general. However, in order for DSM to be an effective energy risk management tool that complements existing strategies and encourage participation from a wider range of participants there are a number of key developments required to allow market forces to increase financial incentives to engage in DSM.

Some of the key benefits include:

- Reduced price spikes. Less than 1 per cent of electricity costs represent 20 per cent of wholesale market revenue. This implies that spikes are relatively infrequent but are large and valuable. Hence, a small amount of DSM in a tight demand-supply environment or region of network constraints may influence spot price at the margin and result in a significant reduction in spot price and provide significant returns to customers who have participated. Recently, DSM resulted in US\$650 million in savings in the PJM market during a heat wave in August 2006. Voluntary load curtailment by energy users resulted in reductions in market price of up to US\$300/MWh.
- Reduction in network constraints and hence increased inter-connector flow and a reduction in spot prices during crisis events or periods of high demand and price.
- Involvement of the mass-market sector in DSM will encourage innovation and new entrants such as aggregators and potentially financial market participants.
- Increased liquidity in the short-term market enabling new entrants and financial intermediaries to better deal with short-term price risk management. However, this is likely to be a residual benefit of DSM and not a key contributor to an active short-term trading market due to the infrequent occurrence and non-firm nature of DSM activities.
- Removal of retail price caps and involvement of the residential market will provide commercial incentive for distributors and energy retailers to focus on ways for DSM to reduce pressure on their networks. There are numerous options that can be explored in this regard including the introduction of new tariff/contract arrangements where consumers sign up with full knowledge that various appliances or other demand sources can be switched off at various times according to pre-defined triggers.
- DSM benefits flow to network investment reduction (and capex deferral) as well as financial and physical market improvements.
- Increased inter-connector flow due to a reduction in network constraints across some regions. Figure 61 illustrates a region within the NEM that experiences significant constraints during high demand periods that can decrease flow on the QLD –NSW inter-connector by up to 200MW. Energy Response estimate that 5MW of DSM in the area of the shaded area would allow another 200MW to flow from Queensland. This is quite a significant increase in inter-connector flow and could potentially results in a substantial reduction in spot prices in NSW during times of market distress.

Figure 61
Example of Network Constraint Area



Source: Energy Response

10.7 Recommendations

Recommendations

The Parer Review made a number of recommendations designed to allow utilisation of DSM by participants to evolve through competitive market forces that are still relevant today. These recommendations relate to:

- the removal of price caps to encourage competition in the residential sector and provide the incentive for energy retailers, distributors, end-users and other parties to more effectively utilise DSM capacity and reduce its transaction costs; and
- implementation of interval/smart metering at the residential level.

Facilitation of improved liquidity in the short-term derivatives market and continued growth of the SFE futures market will provide increased price transparency that will assist in valuing DSM and encourage further participation amongst energy users and participants across the NEM.

A Terms of Reference

ERIG commissioned KPMG to report on:

- the level and nature of trade in Australia's energy financial markets compared with:
 - the ideal given the operating realities of the NEM; and
 - selected energy markets around the world and other commodity markets:
- market rules, structures or practices that impede the efficient operation of Australia's energy financial markets and how material impediments be removed to enhance efficiency:
- mechanisms to improve the efficient use of credit capital and improve management of credit –related risks; and
- impediments to the efficient operation of demand-side management (“DSM”) in Australia and potential improvements.

B Emission and renewable energy schemes in Australia

An Extract from KPMG report for ERIG Review of Energy Related Financial Markets: *Impediments to investment in Australia's energy market, November 2006.*

This section outlines the nature of the Federal and State Governments' policies in regard to greenhouse gas emissions and renewable energy.

B.1 Greenhouse gas and renewable energy policy

Australia currently has a number of policies associated with addressing greenhouse gas emissions and promoting renewable energy. We briefly summarise the key policies below.

B.2 Federal Government policies

As at March 2006 the Federal Government claimed to have over eighty policy measures in place to combat climate change.³⁹ Below we outline the key policies.

- **Asia Pacific Partnership**

The Asia Pacific Partnership includes Australia, China, the USA, Korea, Japan and India (which account for about 50% of global emissions) and commenced in January 2006. Its objective is to accelerate the adoption of new technologies, which lower emissions. It has established eight government and business taskforces on: cleaner fossil energy; renewable energy and distributed generation; power generation and transmission; steel; aluminum; cement; coal mining; and building and appliances. Asia-Pacific Partnership Ministers will meet again in 2007.

- **Low Emissions Technology Demonstration Fund**

The objective of the \$500 million fund established in 2004 is to assist Australian companies to develop new technologies. It is proposing as its first investments to provide \$75 million to support the development of a large solar energy electricity generation facility in Victoria and \$50 million on new brown coal low emissions technologies (with matching funding of \$50 million and \$30 million from the Victorian Government for each project).⁴⁰

- **Greenhouse Gas Abatement Programme (GGAP)**

The GGAP aims to reduce Australia's net greenhouse gas emissions by supporting activities that are likely to result in substantial emissions reductions or activities to offset greenhouse emissions, particularly in the 2008-2012 period. It provides subsidies to private initiatives

³⁹ <http://www.orer.gov.au/publications/mret-overview.html>

⁴⁰ Australian Financial Review, 'Solar power plant grant backfires on Vic Liberals', 26 October 2006, page 3.

for qualifying projects. There have been three funding rounds. No further rounds are envisaged under this program.

- The Commonwealth Mandatory Renewable Energy Target (MRET)

The MRET aims to increase renewable electricity generation by encouraging the generation of an additional 9,500 GWh of renewable energy per year by 2010. MRET operates by imposing a legal liability on generally large wholesale purchasers of electricity to buy a certain amount of that electricity from renewable sources. It ends in 2020. The target is expected to be reached in 2007 and the Government is not proposing to expand the program.

- Energy Efficiency Opportunities (EEO)

EEO requires companies to undertake a detailed review every five years to identify energy efficiency opportunities. Companies will be required to publicly report the findings of their review to the public in order to demonstrate that the company is using energy efficiently.

- Other key policies

The Federal Government is committed to not introducing a carbon tax or an emissions trading scheme (unless it is comprehensive and international) on the basis that it would damage Australia's economic interests.

The Federal Government is committed to not ratifying the Kyoto Protocol on the basis that it is an ineffective method of limiting greenhouse gas emissions because it does not include developing countries. The Government expect to meet the target it would have had under ratification.⁴¹

The Federal Government is proposing that nuclear energy should be part of the solution to greenhouse gas emissions. Speaking at the 15th Pacific Basin Nuclear Conference Federal Resources Minister, Ian Macfarlane, stated that:

The reality is that nuclear technology is here, it is now, and it is available to be introduced into Australia's energy mix to reduce greenhouse gas within 10 years. As third generation plants become a reality, there are forecasts of full-cycle nuclear power costing as little as 5 cents a kilowatt hour. That's in comparison with 3.5 cents an hour for coal, 4.5 cents for gas and 8 cents for wind and 12 cents for solar power.

He is, however, also of the view that the industry would need to be viable without government support.⁴² Meanwhile other members of the Government have warned that nuclear power is probably not economically viable in Australia and/or that it would be necessary to subsidise it.

⁴¹ <http://www.deh.gov.au/minister/env/2006/mr23may406.html>

⁴² ESSA, 'Nuclear debate hots up', ESSA News, Issue 2, 23 October 2006, page 1. See also Australian Financial Review, 'Minister warms to nuclear power', 17 October 2006, page 3.

B.3 State Government policies

The states are jointly proposing a National Emission Trading Scheme (NETS). In August 2006, the NETS Task Force released a discussion paper outlining possible design options. The NETS would place a cap on the greenhouse gas emissions that a covered sector could emit. The discussions paper suggests that NETS could start as early as 2010 and would in the first instance cover the stationary energy sector.

At the individual level, the key State Government policies are as follows:

- New South Wales

The NSW Government's objectives are to ensure that emissions in 2025 are no greater than 2000 levels and to reduce emissions by 60% in 2050.⁴³ It has a variety of policies in place including domestic building standards, a commercial building ratings scheme, an energy savings fund, carbon rights legislation, and a Renewable Energy and a Greenhouse Gas Abatement Scheme (GGAS).

The GGAS commenced on 1 January 2003. GGAS establishes annual NSW greenhouse gas reduction targets. The scheme requires individual electricity retailers (and some other parties) to meet mandatory benchmarks based on their share of the electricity market. The Government recently announced its intention to extend the scheme from 2012 to 2021 (or until the establishment of a national emissions trading scheme).

- ACT

The ACT Government introduced a Greenhouse Gas Abatement Scheme on 1 January 2005, which mirrors the NSW Greenhouse Gas Abatement Scheme.

- Queensland

The Queensland Government's key greenhouse policies involve promoting energy efficiency, and subsidising both the development of clean coal technology and the wider use of gas in electricity generation.

Under the Gas Electricity Certificate (GEC), Queensland electricity retailers and other liable parties are required to source at least 13% of their electricity from gas-fired generation. The scheme's aim is to encourage the development of new gas sources and infrastructure in Queensland and to reduce greenhouse gas emissions. The scheme commenced in January 2005 and will run until 2020.

- South Australia

The Government's objective is to reduce greenhouse gas emissions to 60% of 1990 levels by 2050. It is currently developing a renewable energy program. It is expected to be based

⁴³ http://www.greenhouseinfo.nsw.gov.au/__data/page/927/28-11_FINAL_NSW_GH_Plan_web.pdf

on the Victorian Government renewable scheme, and require increasing renewable energy use to 20 per cent of its electricity consumption by 2014.

- Tasmania

Tasmania recently produced a Draft Climate Change Strategy for public comment. It is amongst other things supporting the development of a national emissions trading scheme.

- Victoria

The Victorian Government has about 19 policy initiatives in place focussing on producing greenhouse friendly energy, improving energy efficiency and adapting to climate change. The policies in the first two categories include: domestic and commercial building standards; appliance standards and labelling schemes (part of a national initiative); electricity interval meter roll-outs, subsidising clean coal electricity generation projects; requiring large users to develop industry energy efficiency plans; and the Victorian Renewable Energy Target (VRET).⁴⁴

VRET requires electricity retailers to purchase a minimum of 10 per cent of their energy needs from renewable energy by 2016. The targeted start date is 1 January 2007 and it is expected to run until 2025.

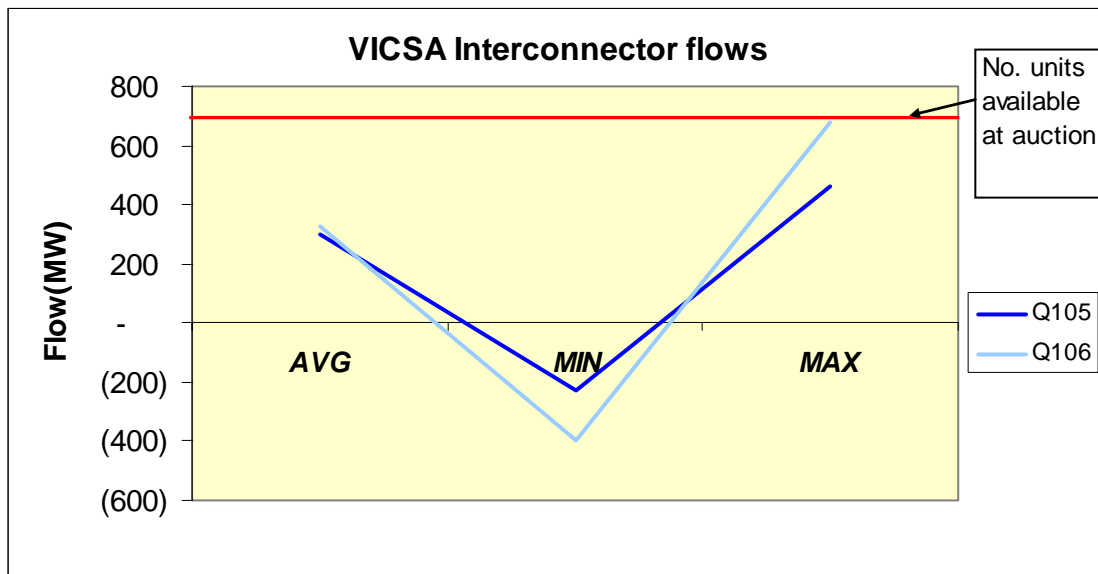
⁴⁴ <http://www.dse.vic.gov.au/ourenvironment-ourfuture/downloads.htm>

C Inter-regional trade – additional information

C.1 Inter-connector flow and SRA firmness analysis

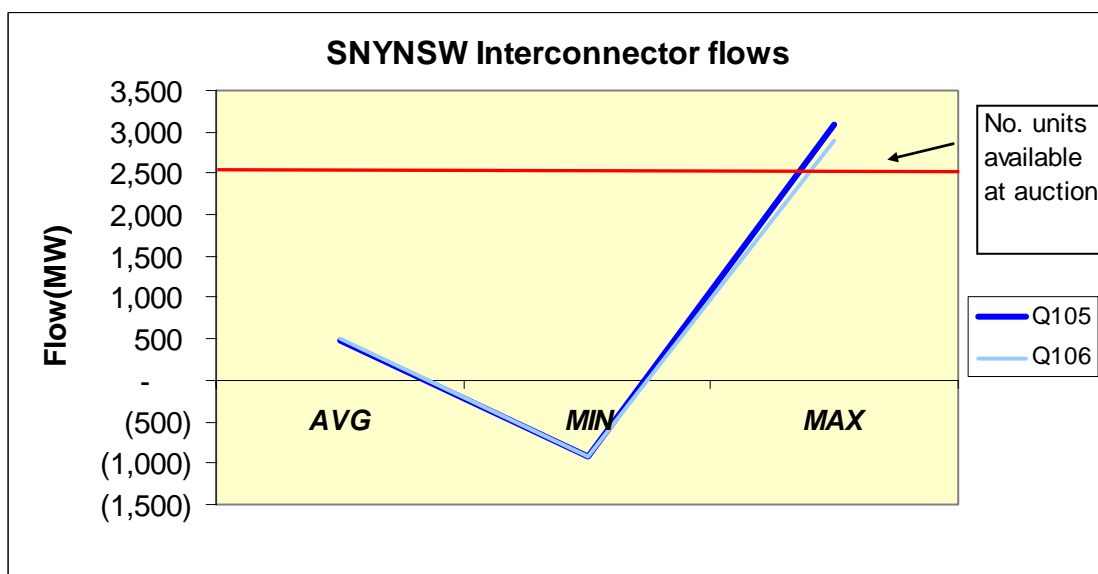
- SNYNSW and VICSA were selected for analysis
- Analysis was performed for Q1 and Q2 (05 and 06)

Figure 1 VIC to SA interconnectors flows for Q105 and Q106



Source: NEMMCO, KPMG Analysis

Figure 2 SNY to NSW interconnectors flows for Q105 and Q106



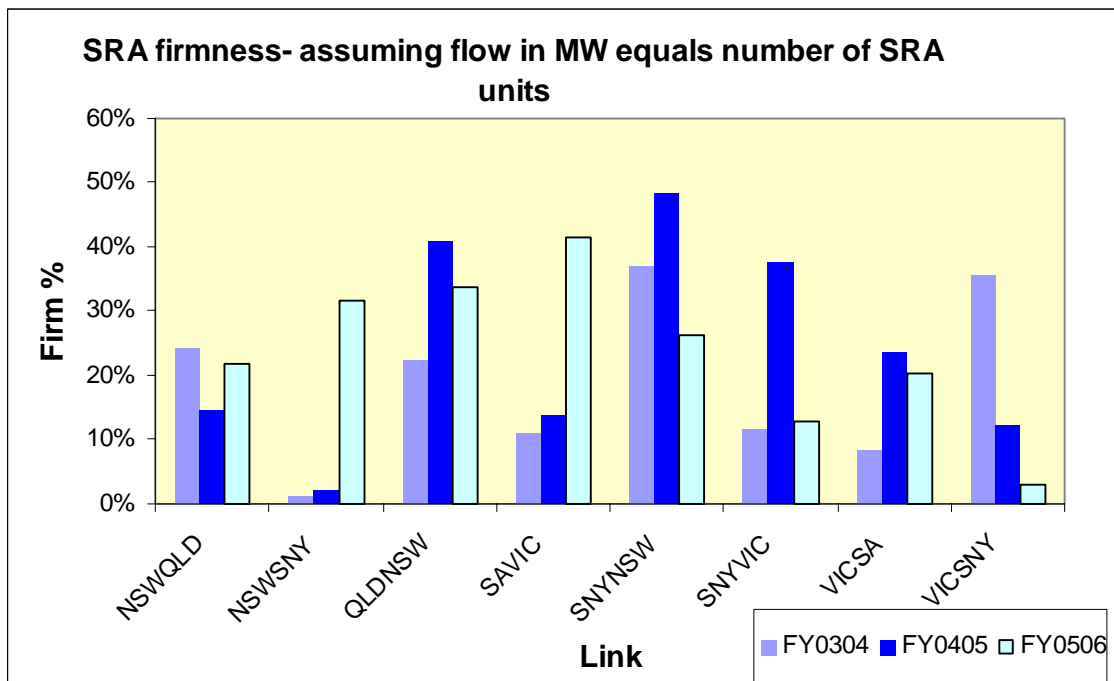
Source: NEMMCO, KPMG Analysis

SRA Firmness analysis

Figure 3 below models the residue distributed by NEMMCO for each link across Fin03/04, 04/05 and 05/06 and compares the residue (firm cash flows) that would have accumulated if the link flowed at a level equal to the number of SRA units available at auction e.g. The firm cash flow for SNYNSW is calculated using the price differential between SNOWY and NSW multiplied by a flow of 2500MW (ignoring negative flows).

The analysis present illustrates the well known fact that interconnector flows are variable and hence subject to significant volatility over time.

Figure 3 SRA Firmness – assuming flow in MW equals number of SRA units

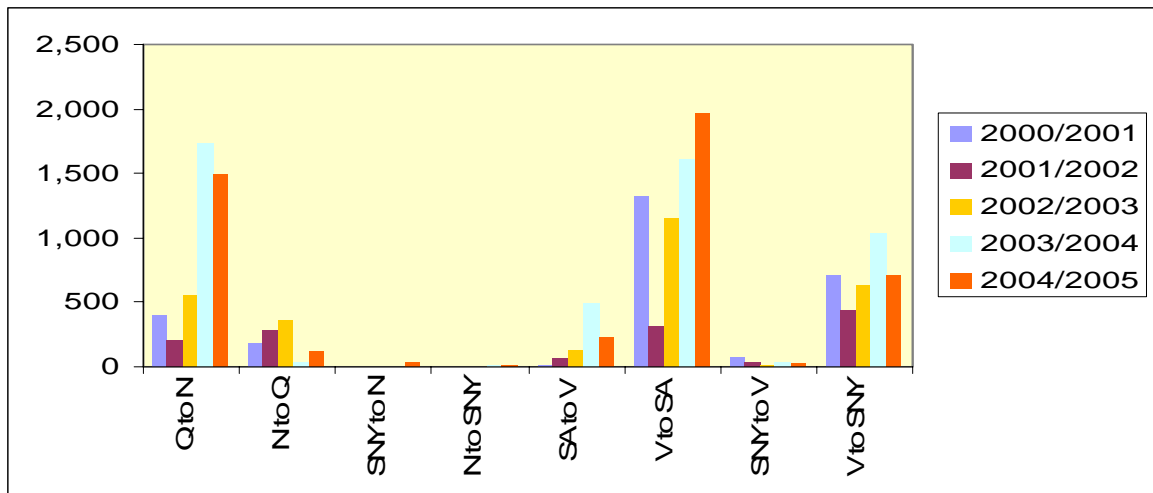


Source: NEMMCO, KPMG Analysis

System constraints

The Chart below illustrates the number of constraints across each inter-connector link during system normal operation.

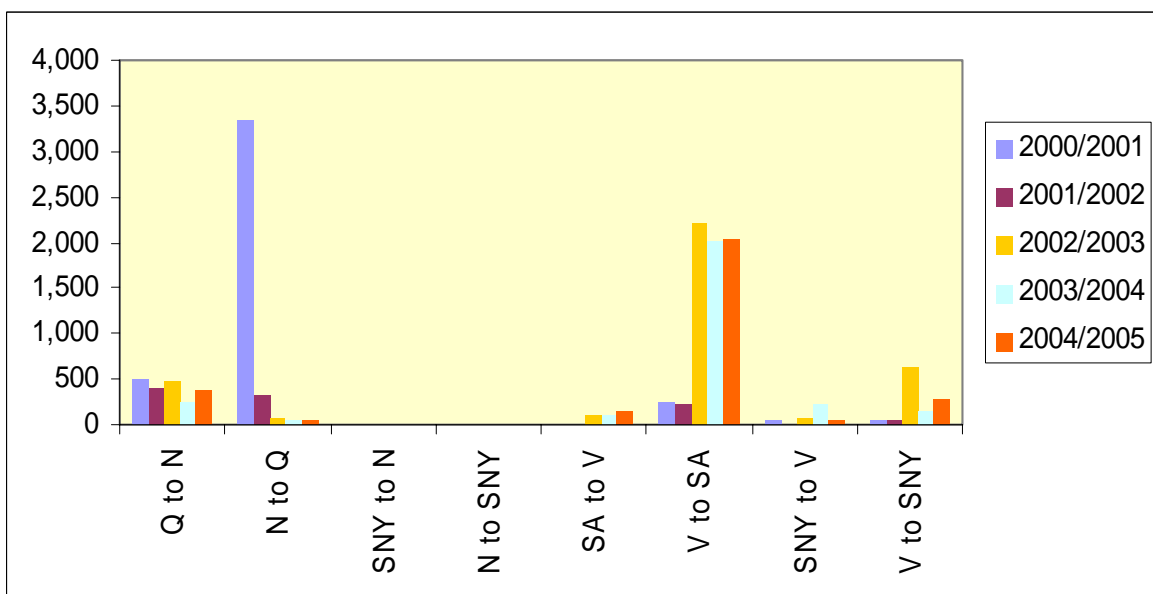
Figure 4 Constraints during normal operation



Source: NEMMCO, KPMG Analysis

The Chart below illustrates the number of constraints across each inter-connector link during system outages.

Figure 5 Constraints during system outages



Source: NEMMCO, KPMG Analysis

Inter-regional hedging Case Study

Scenario:

Retailer in QLD hedging 20MW of exposure for 1 quarter using three strategies. They are:

- 1 QLD swap*
- 2 NSW swap plus NSW-QLD SRAs to derive synthetic QLD swap*
- 3 NSW swap plus inter-regional swap (sell NSW buy QLD)*

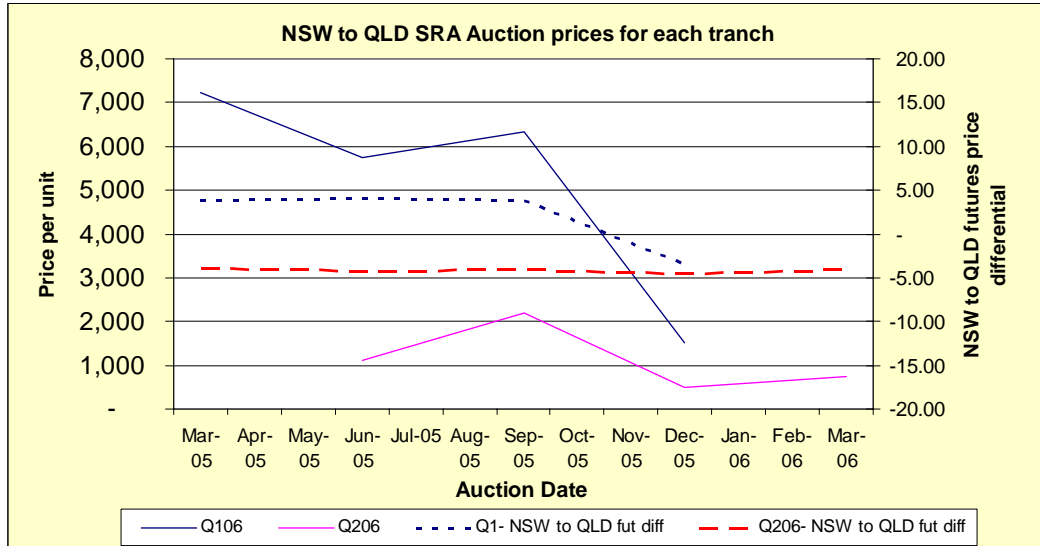
Note: A flat 20MW load is assumed in this example

Data and assumptions:

- SFE futures prices for Q106 in QLD (average of \$49.75) and NSW (average of \$47.41) coinciding with SRA auction dates
- NSW to QLD SRA unit prices were analysed at each auction date
- Whilst market participants often purchase more SRA units than their estimate MW exposure (due to an assumption that SRAs are non-firm) we have assumed that 20 SRA units are purchased (in line with price exposure of 20MW).

Illustrative analysis:

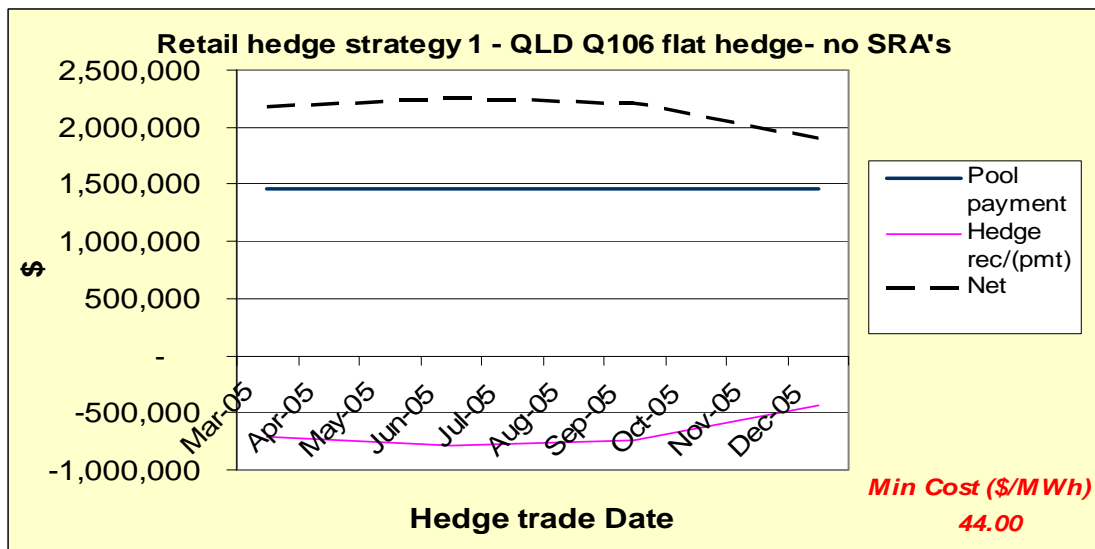
The analysis performed involved the comparison between SRA prices (NSW to QLD) and NSW and QLD forward swap rate for the period Q1 2006. In order to demonstrate the potential variability in swap rates as well as SRA unit prices this analysis was undertaken for a series of dates coinciding with the SRA dates for Q106 SRAs and indicates that the timing and rate paid for the SRA units and swaps significantly impacted on the net hedging result. That is, if in Q106 if NSWQLD SRA units were purchased during the first auction tranche, the price paid was \$7215 were as the last tranche for Q106 was priced at \$1501 (refer to the chart below).



Source: KPMG Analysis

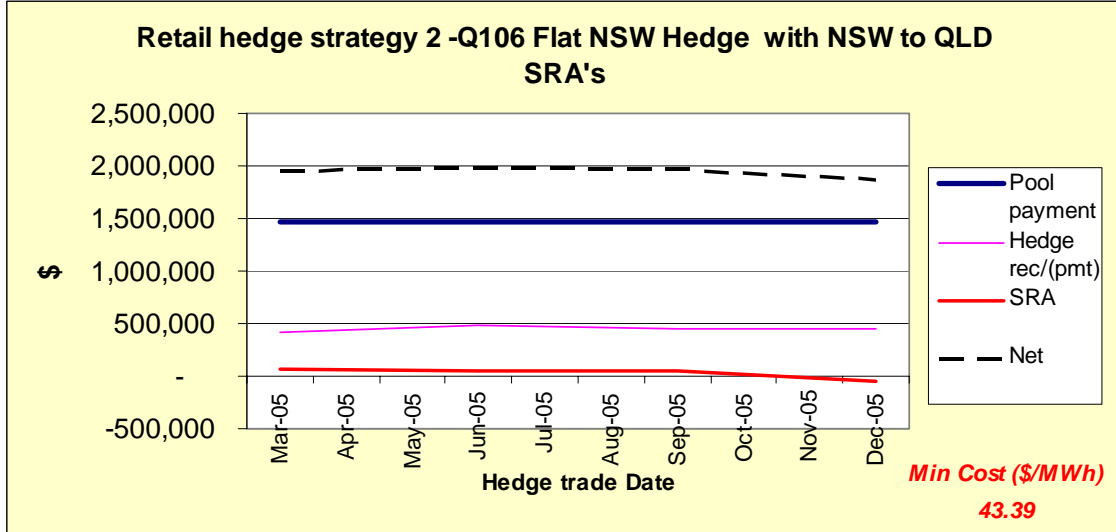
Results:

Hedge option 1: Managing price exposure using a QLD swap



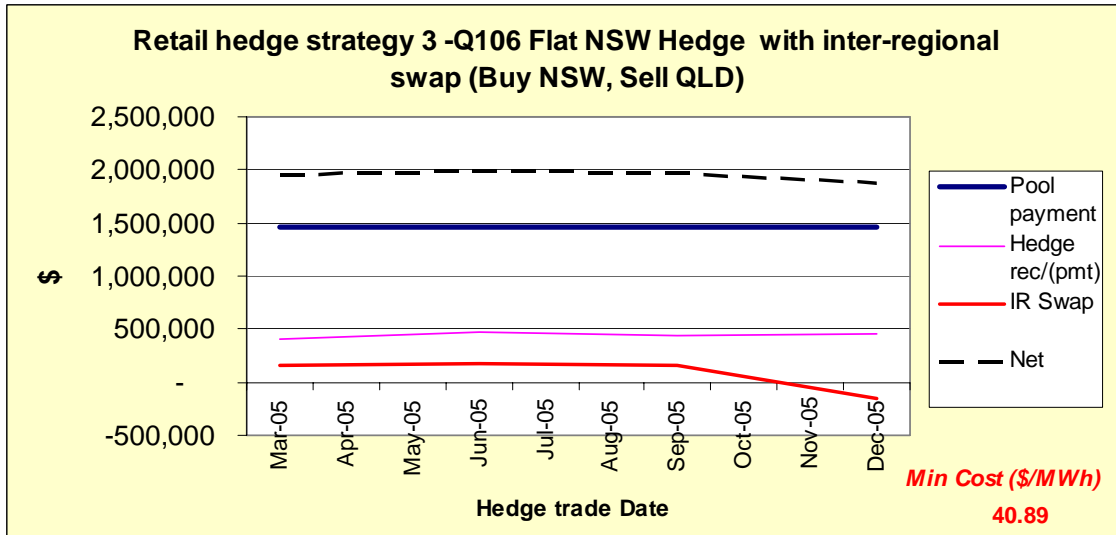
Source: KPMG Analysis

Hedge option 2: Managing price exposure using a NSW swap in conjunction with NSW to QLD SRAs.



Source: KPMG Analysis

Hedge option 3: Managing price exposure using a NSW swap in conjunction with an inter-regional (NSW/QLD) swap



Source: KPMG Analysis

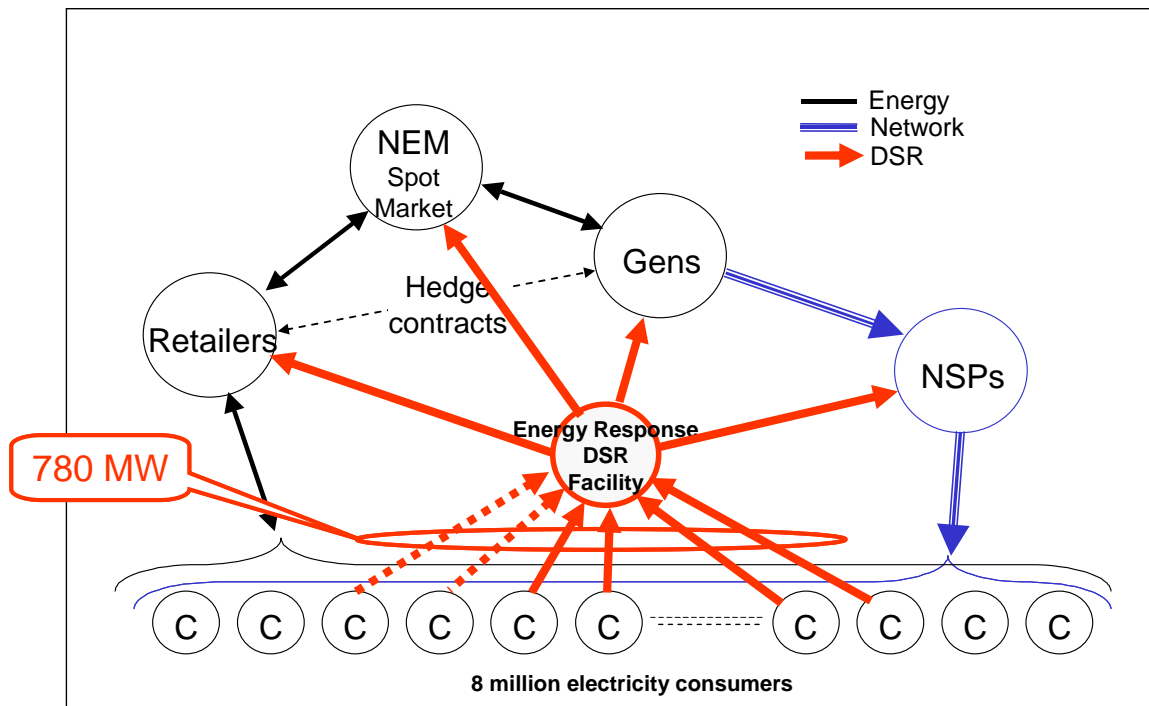
Results:

- Both inter-regional hedging strategies resulted in a net purchase cost lower than the intra-regional QLD hedge (which had a minimum price of \$44/MWh over the period analysed.)
- The effective hedge price can be potentially improved using SRAs however the result varies depending on the price paid for the SRAs and also the price-separation and inter-connector flow NSW to QLD. See the chart below illustrating the SRA prices for Q106 across the four auctions held.
- The best-case inter-regional swap payoff was significantly more than the SRA payoff due to the firmness associated with the fixed load covered by the swap. However, an inter-regional swap also introduces an element of risk related to the fact that QLD can trade below NSW whereas the SRA payoff only occurs when QLD spot prices are greater than NSW prices and the inter-connector is flowing from NSW to QLD.

The chart below shows the results of hedge strategy 3 which involves an inter-regional swap.

D Demand Side Management

D.1 The Energy Response model



Source: Energy Response