J Frontier Economics - Implications for the National Electricity Market from increases to the Market Price Cap and/or Cumulative Price Threshold

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A REPORT PREPARED FOR THE AUSTRALIAN ENERGY MARKET COMMISSION

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Executive summary

Frontier Economics has prepared this report to advise the AEMC on the non-reliability implications of increasing the MPC and CPT across the following range of areas:

- investment and spot prices
- likely degree of demand-side response
- prudential requirements and consequential impacts on retail competition
- contract market liquidity, risk premia and prices
- likely exercise of transient market power
- inter-regional trade
- transitional and systemic risks.

Wholesale investment and spot price impacts

In an energy-only market such as the NEM, investors in generation capacity are required to recover their total costs through the spot market or derivative contracts settled against spot market outcomes.

Using our proprietary model, WHIRLYGIG, we modelled likely generation investment patterns with different levels of the MPC. In general, a higher MPC was associated with more investment in generation capacity, particularly OCGT peaking capacity.

We also considered the potential impact of a higher MPC on spot prices. In principle, a higher MPC should increase generators' incentives to directly or indirectly exercise transient market power. Properly understanding how these influences could play out in practice would require a more complex modelling exercise than our scope allows. Nevertheless, we would expect that while generators would continue to offer the bulk of their capacity to the market at or about their SRMC, on the margin, they would increase the price of their offers above $300/MWh. This is approximately at the top of peaking generators' SRMCs in the NEM and about the level of cap strike prices.

Assuming that generators only increased the price of offers above $300/MWh in response to a higher MPC, we hypothesised how historical average spot prices in each region might have been different with higher MPCs. We found that the results varied greatly according to the relevant year for which historical prices were adjusted and that the extent and variance of average price uplift increased non-linearly with the level of MPC. We also found that the mid-point estimate of average price increases for different MPCs varied according to the peakiness of prices – and hence load – in each region.

Demand side response

DSR provides a number of benefits to participants and to the market as a whole. Participants can gain financially if customers agree to curtail consumption at peak times. The market as a whole can benefit from improved allocative, productive and dynamic efficiency as resource allocation improves in both the short and long run.

Consumers can engage in DSR directly, through participation in the wholesale market trading arrangements, or indirectly, through contracting with retailers. Direct participation is extremely uncommon and DSR contracting is also relatively rare at the present time.

At this stage, there is simply insufficient empirical evidence to reasonably predict the quantitative impact of higher MPCs on the level of DSR in the NEM. However, several general comments can be made:

- A higher MPC should, at the margin, increase the quantum of observed DSR by residential and business consumers
- As the MPC rises, the quantum of DSR should increase at a decreasing rate.
- However, DSR from smaller customers requires investment in real-time metering or other demand management systems and a sustained political willingness to allow customers to face time-varying prices and/or automated supply interruptions. This willingness appears to be limited at the moment.

Prudential requirements

The prudential requirements in the Rules are intended to cover AEMO's worst case exposure to potentially defaulting market participants. The derivation of the reasonable worst case scenario takes account of historical spot price volatility in the NEM. To the extent that an increase in the MPC leads to an increase in wholesale spot prices, this is likely to increase this worst case exposure, and thereby increase participants' prudential obligations. Other things being equal, this could raise barriers to entry, particularly for new retailers.

There appears to be no simple means of overcoming the greater barriers to entry for retailers from a higher MPC without compromising the financial integrity of NEM settlements.

Risk management implications

A higher MPC could reasonably be expected to increase the prices of financial risk management instruments. An increase in hedge prices could be the result of increases in spot prices and/or the impact of greater spot price volatility on hedging premiums. Generators benefit from the higher premiums on these options. This is consistent with the rationale to increase MPC, which is to stimulate investment in new capacity.

In the absence of a dedicated modelling exercise, it is difficult to estimate how much hedge prices could rise at different levels of the MPC. However, we note that swap premiums in the NEM have consistently been about $2/MWh over spot prices.

The implications of higher MPCs on hedge market liquidity and duration are less clear. However, we see no reason to expect a large drop-off in liquidity given the near-secular increase in Sydney Futures Exchange-traded NEM hedging instruments over the past 4-5 years. We expect the now relatively mature market for hedging instruments will be able to quickly respond to changes in market participants' hedging needs due to an increased MPC. In our view, this suggests no need for policy interventions in hedging markets due to an increase in MPC and CPT.

Market power

A high MPC can create incentives for generators to exercise transient market power in the NEM. While this may not raise broader *Trade Practices Act* concerns, if it occurs frequently, transient market power can raise wholesale prices and compromise economic efficiency in both the short and long run. Increasing the MPC is likely to increase existing incentives to exercise transient market power because it increases the 'payoff' to any given generator from engaging in economic withholding strategies.

Various regulatory and market design options are available to mitigate generators' incentives to exercise transient market power. The regulatory options include measures to restrain generators' offers directly and downward adjustments to the MPC and/or CPT. The market design options include implementing some form of capacity mechanism to sit alongside the energy-only market. However, all of these options have drawbacks and create risks of their own for the maintenance of sufficient capacity to help meet the NEM reliability standard.

Inter-regional trade

Raising the MPC and CPT could indirectly influence inter-regional trade in both the short and the long term.

In the short term, a higher MPC could change the pattern of transmission constraints in the NEM. However, it is very hard to generalise about the tendency, nature or costs of these effects. It is clearer that a higher MPC would be likely to further increase the basis risks of inter-regional contracting in the NEM. This could discourage inter-regional hedging and may ultimately contribute to inefficient longer term locational signals for new investment.

In the longer term, to the extent that a higher MPC results in less firm IRSR units and deters participants from entering inter-regional electricity derivatives, a higher MPC may distort the locational decisions of new generation investors. New generators may be more encouraged to locate in the same regions as their intended counterparties than is warranted on the basis of the underlying relative costs.

However, by reducing the gap between the MPC and the Value of Customer Reliability, a higher MPC could reduce the present bias in favour of regulated investment under the existing network regulatory arrangements. We agree with the AEMC that applying different MPCs in different regions could bring a range of unintended and perverse outcomes.

Transitional and systemic risk issues

An increase in MPC may raise transitional risks for the market. The key issue is to ensure that there is a sufficient lead time between the timing of a formal decision to raise the MPC and its implementation to allow derivative markets to reflect any expected changes to spot market outcomes and to allow participants to arrange any additional prudential support. In our view, the proposed lead time for the proposed increase in MPC to $16,000/MWh from 1 July 2012 is likely to be appropriate if a formal decision to endorse this proposal is made in the near future. We do not consider that the planned increases to the MPC and CPT give rise to any material systemic risks for the market.

1 Introduction

1.1 Background

Frontier Economics (Frontier) has prepared this report to the Australian Energy Market Commission (AEMC or Commission) to inform the Commission of the non-reliability implications to the NEM of increases to the Market Price Cap (MPC) and/or Cumulative Price Threshold (CPT). The MPC is the cap on regional reference prices (RRPs) in the NEM and the CPT sets a threshold for the application of the Administered Price Cap.[1]

The Commission is presently investigating whether the MPC, CPT and market floor price should be changed in the context of the:

- Reliability Panel's Review of Operational Arrangements of the Reliability Standard and Settings
- MCE-initiated Review of Effectiveness of NEM Security and Reliability Arrangements in light of Extreme Weather Events.

ROAM Consulting (ROAM) has been retained to advise the Commission on the levels of the MPC and CPT needed to meet the existing NEM reliability standard[2] going forward, as well as the inter-relationship between different levels of the MPC and CPT and expected levels of unserved energy (USE).[3]

ROAM's Draft Report proposes an increase in the MPC from $12,500/MWh (to apply from 1 July 2010) to $16,000/MWh for 2012-13 and 2013-14 and a corresponding increase in the CPT from $187,500 to $240,000 (retaining a multiple of 15 times MPC).[4] This report does not discuss the market price floor.

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1 The MPC replaced the NEM's original VoLL (Value of Lost Load) from 28 May 2009 following the Commission's Final Determination on NEM reliability settings (see AEMC website here). The Cumulative Pricing Threshold was introduced in 2000, at the same time as the previous force majeure arrangements were removed.

2 The AEMC Reliability Panel has recently recommended minor changes to the NEM reliability. Under the modified standard, the maximum expected USE is 0.002% of the annual energy consumption for the associated region(s) per financial year. See AEMC Reliability Panel, *Reliability Standard and Settings Review*, Draft Report, 23 December 2009, available here, Appendix C, pp.39-40.

3 See ROAM Consulting, *Reliability Standard and Settings Review*, Draft Report to the AEMC, 15 January 2010, available here.

4 ROAM Consulting, *Reliability Standard and Settings Review*, Draft Report to the AEMC, 15 January 2010, p.27.

1.2 Report purpose and structure

This report advises the AEMC on the non-reliability implications of increasing the MPC and CPT. It does not comment on the sufficiency or otherwise of the proposed increase in the MPC and CPT for promoting sufficient generation investment to meet the NEM reliability standard. Implications are considered in the following areas:

- investment and spot prices (section 2)
- likely degree of demand-side response (section 3)
- prudential requirements and consequential impacts on retail competition (section 4)
- contract market liquidity, risk premia and prices (section 5)
- likely exercise of transient market power (section 6)
- inter-regional trade (section 7)
- transitional and systemic risks (section 8).

2 Wholesale investment and spot price impacts

This section begins by considering the role of the MPC and CPT in the NEM, and then applies various methods to derive the potential indicative effects on investment and spot prices if the MPC and CPT were increased.

2.1 Role of the MPC and CPT

The NEM is an energy-only, compulsory wholesale spot market. This means that all electricity generated in the NEM must be traded through the NEM spot market.[5] Electricity has a number of characteristics that mean its spot price can be extremely volatile:

- power system security requires that electricity supply must equal demand at all times
- electricity cannot (yet) be economically stored
- demand is highly unresponsive to price, especially in the very short term.

These characteristics also mean that supply may physically not always be able to meet demand, and in the absence of an artificial price cap there is no price at which the market will clear. In these circumstances the market and system operator is required to shed load involuntarily and to set a market price in lieu of the market failing to clear. The MPC provides a maximum RRP that can be set in the NEM,[6] while the CPT sets a threshold for the cumulative value of transactions over a 7-day rolling period (ie 336 half-hourly trading intervals) beyond which the Administered Price Cap applies.[7]

The role of spot market prices in stimulating generation investment varies according to the design of the market. In an energy-only market like the NEM, generators are required to recover their variable operating costs as well as their fixed and sunk costs through spot market revenues and derivative contracts settled against spot market outcomes. This means that the spot price needs to rise (or at least be expected to rise) at certain times above the operating cost of the plant with the highest variable operating costs in the market to enable these plant to recover their fixed and sunk costs. By contrast, some market designs incorporate capacity mechanisms that separately compensate generators for at

5 With the exception of exempt generators, which must be less than 30MW in size and account for a very small proportion of energy output in the NEM.

6 See clause 3.9.4 of the Rules.

7 See clause 3.14 of the Rules.

least a share of their fixed and sunk costs. In these markets, it may not be necessary for the spot price to rise above peaking plants' operating costs.

In principle, an energy-only market can signal the least-cost mix of generation capacities and technologies to meet the forecast level and pattern of electricity demand. It does this by setting price at the market-clearing bid or offer and allowing the level and shape of the market's load profile to drive prices up or down for different periods of time to produce the required forecast revenues of the most efficient plant mix.

Importantly, there is no need for generators to bid above their operating costs in order for spot prices in an energy-only market to recover total costs in the long run. As noted above, at least for some of the time, spot prices will exceed the variable operating costs of all but the most costly plant in the market. Plant with the highest variable costs need not bid above this level, since these plant should be able to recover their fixed and sunk costs at times when supply does not meet demand and the MPC applies or a demand-side bid sets the spot price.[8]

Other things being equal, the higher the MPC:

- the higher will be expected average wholesale spot prices *in the long term*[9]
- the stronger the signals for additional generation capacity to avoid the risk of unserved energy
- the higher the expected level of 'reliability' (as measured by forecast USE).

In a market with a relatively unresponsive demand side (like the NEM), the appropriate trade-off between average spot prices and reliability is a question for policy-makers. In the sections below, we provide our views on the potential impact of a higher MPC on investment and spot prices.

2.2 Investment modelling

This section explains the results we obtained from modelling the effect of different levels of MPC on patterns of investment in the NEM. We used Frontier's proprietary market development model, *WHIRLYGIG*, to find the least-cost mix of generation plant that ensures:

- supply equals demand at all times
- minimum reserve requirements are met
- generators do not run for more than their physical capacity factors

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8 See Stoft, S., *Power System Economics, Designing Markets for Electricity*, IEEE Press 2002, pp.120-129.

9 Although a higher MPC could be expected to lead to more generation investment, which may depress spot prices for a time, a long run equilibrium of higher investment would only be sustainable if average wholesale prices were also higher than they would be under a lower MPC.

- additional policy constraints – including greenhouse policies – are met.

WHIRLYGIG determines the pattern of dispatch and investment that minimises the total cost of meeting load growth over time, subject to various constraints such as those noted above.

Our modeling did not seek to duplicate or replicate ROAM's modelling and differs from it in a number of important ways:

- *WHIRLYGIG* was used to model the entire year's load rather than just focusing on the super peak hours of demand. This means that our analysis identifies the full investment path in terms of size, type, timing and location of new investment to meet demand, rather than only considering the viability of the marginal new entrant peaking plant.
- *WHIRLYGIG* assumes a perfectly competitive market. That is, all capacity is assumed to be bid into the market at SRMC. By contrast, ROAM applied historical bidding patterns.[10]
- *WHIRLYGIG* is a deterministic model and does not treat plant outages stochastically. Plant are de-rated within the model to account for expected outage rates.

We based the input assumptions used in the model on publicly available data, relying to a large extent on the following two sources:

- AEMO's *2009 Statement of Opportunities for the National Electricity Market* (AEMO 2009 ESOO)
- ACIL Tasman's *2009 Fuel resource, new entry and generation costs in the NEM (Final Report)*, prepared for the Inter-regional Planning Committee in April 2009 (ACIL 2009 report).

We based our assumption set on the data used in our advice to the Independent Pricing and Regulatory Tribunal (IPART) regarding the current NSW retail price determination. Full details of Frontier's assumptions are available on the IPART website.[11]

In order to investigate the impact of altering the MPC, we made two changes to this set of assumptions:

- an expected outage rate of 3% was assumed for new peaking plant. This assumption was discussed with, and agreed to by, the Commission.

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10 ROAM Consulting, *Reliability Standard and Settings Review*, Draft Report to the AEMC, 15 January 2010, pp.23-24 and Appendix A5, p.VI.

11 Frontier Economics. *Modelling methodology and assumptions*, prepared for *Independent Pricing and Regulatory Tribunal*, August 2009, available here.

- a different demand profile has been used in the model with a much greater focus on peak demand times. This is necessary given that relatively short periods of MPC prices can have large impacts on modelled outcomes. In order to adequately capture these impacts a higher level of demand resolution at peak times is warranted.

In all cases, we made the following key assumptions:

- Demand is consistent with the AEMO 2009 ESOO forecast for the high growth scenario and a 10% probability of exceedence
- Existing supply is consistent with the AEMO 2009 ESOO
- Generator cost data are consistent with the ACIL 2009 report
- The CPRS is introduced on 1 July 2011 with a carbon price in line with the Commonwealth Treasury's CPRS-5 case.
- The expanded MRET scheme is met. We did not alter the target of this scheme to reflect the recently proposed changes to the scheme. We do not consider this to be a driving factor in this analysis.

2.2.1 Modelled scenarios and results

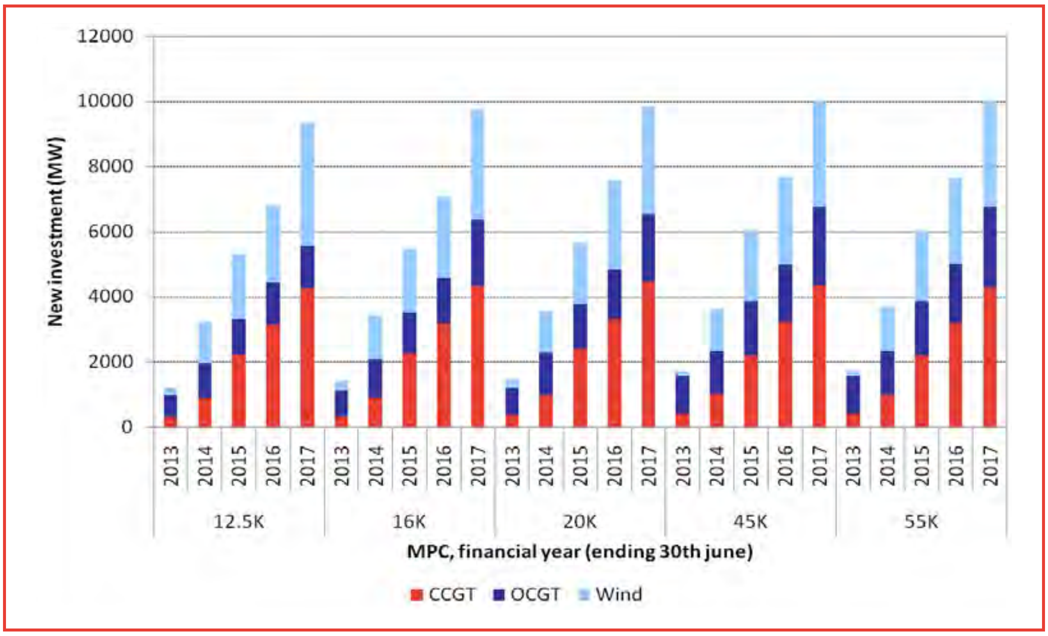
We modelled five scenarios over the modelling period 2012/13 to 2016/17. These five scenarios correspond to the following different MPC levels:

- $12,500/MWh (12.5K)
- $16,000/MWh (16K)
- $20,000/MWh (20K)
- $45,000/MWh (45K)
- $55,000/MWh (55K).

A key output from *WHIRLYGIG* is an investment path that minimises the total cost of meeting load growth over time. Figure 1 shows the NEM investment path for each of the MPC scenarios modelled. The basic trend is for a mix of investment in baseload combined-cycle gas turbine (CCGT) plant, wind plant to meet MRET requirements and peaking open-cycle gas turbine (OCGT) capacity to minimise unserved energy.

As expected, raising the MPC is associated with a greater quantity of peaking plant entering the NEM. For the MPC $12.5K case, approximately 1,300 MW of OCGT capacity is built in 2016/17. In the MPC $55K case, this increases to approximately 2,500 MW. Installed capacity of baseload CCGT and wind also change in response to different MPCs. However, these movements are not as large.

Figure 1: New investment for the NEM by MPC scenario



Source: Frontier Economics

2.3 Potential impact on spot prices

In order to robustly forecast spot prices under different MPCs, it would be necessary to undertake a multi-stage modelling process. This would involve modelling the impact that a higher MPC would have on:

- investment outcomes – this is a key output from Frontier's least-cost investment model, *WHIRYGIG*
- generator bidding behaviour – Frontier's pool dispatch model, *SPARK*, seeks to project market outcomes based on Nash Equilibrium bidding behaviour.

Forecasting spot prices in such a manner would ensure that the both the short-run (strategic) and long-run (investment) impacts of a higher MPC were captured. However, this is a complex exercise and goes beyond the agreed scope of the modelling undertaken for this report.

In the timeframe available for this report, we considered the potential effects of higher MPCs on spot prices by considering:

- the likely theoretical implications of a higher MPC on the market and particularly generator bidding behaviour
- whether increasing VoLL (the Value of Lost Load, the previous name given to the MPC) from $5,000/MWh to $10,000/MWh in April 2002 had any noticeable impact on wholesale spot prices

- the potential changes in average spot prices that could occur if historic spot price outcomes were scaled in accordance with a higher MPC.

Section 6 considers in more detail the impact of a higher MPC on incentives for generators to offer their capacity to the market strategically.

2.3.1 Theoretical considerations

Generators in the NEM submit multiple price-quantity offers to the market operator, AEMO, on a 5-minute (dispatch interval) basis throughout the day. Each generator can submit up to 10 price-quantity offers for a given dispatch interval, where:

- the 10 'price bands' are fixed for the entire day – at the start of the day generators must set the 10 discrete prices at which they are willing to offer their capacity for dispatch
- the quantity offered at each price band can be updated every 5 minutes by submitting 'rebids'. Rebids allow a generator to shift its available capacity between different price bands in response to real-time market conditions (such as outages and demand fluctuations).

Having received multiple price-quantity offers from all available generators, AEMO aggregates these offers into a single 'merit order' ordered from lowest to highest price. Demand is cleared against this merit order and any (loss-adjusted) offers made by generators below the resulting market-clearing price are dispatched (subject to network and system constraints) and settled at this price.

Generators set their 10 price bands based on, amongst other things:

- short-run marginal cost (SRMC) – this reflects a generator's avoidable resource costs of generating an additional MWh of electricity and *typically* places a lower-bound on the price at which a generator would be willing to be dispatched and settled
- network constraints – in the presence of network constraints, generators may find it profitable to offer electricity to the market at a price below their SRMC
- level of contracting – to the extent generators have sold derivative contracts such as swaps and caps, they will have incentives to offer contracted capacity to the market at SRMC (for swaps) and just below the contract 'strike'[12] price (for caps)

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12 In the context of a cap contract, the 'strike' price is the price above which the seller is obliged to make difference payments reflecting the difference between the relevant spot price and the strike price. For swap contracts, the buyer would also be required to make difference payments if the spot price fell below the strike price.

- transient market power – the extent to which a generator can profitably withhold or shift capacity into higher price bands in order to increase the market price and hence its operating profits
- technical considerations – some generators have minimum stable generation levels. In order to avoid the risk of being ordered to decrease output below these levels, some plant often offer a proportion of their capacity to the market at very low (or negative) prices to ensure dispatch.

Observed bidding behaviour

In practice, generators tend to offer capacity to the market in the following *broad* price ranges:[13]

- a very small amount of capacity at very low or negative prices to cover minimum stable generation levels (except for peaking plant, which are typically not subject to such constraints)
- a large amount of capacity at or near SRMC
- a small amount of capacity at very high 'opportunistic' prices well above SRMC – the highest opportunistic offers often approach the MPC.

There are several reasons why generators in the NEM tend to offer a large proportion of their capacity at prices broadly consistent with their SRMC:

- bidding significantly above SRMC raises the risk of being undercut by a competitor and thus foregoing potential operating profits (price – SRMC).
- generators typically enter into swap contracts in respect of a substantial proportion of their capacity and as such receive no short-term benefits from pushing up the spot price in respect of their (swap) contracted capacity.

To illustrate the typical price-quantity offers made by generators in the NEM, Figure 2 shows the annual distribution of bids made by two generators in the NEM over the course of 2008/9:

- 'AGLHAL' – AGL's Hallett gas plant (peaking oil/gas in South Australia)
- 'ER01' – Eraring Energy's Unit 1 (baseload coal in New South Wales).

As expected given its baseload characterisation, ER01 bid the majority of its capacity at prices around its estimated SRMC of $18/MWh.[14] Remaining capacity was bid close to the market price floor of -$1,000/MWh (due to minimum stable generation constraints) and opportunistically at prices above $9,000/MWh.

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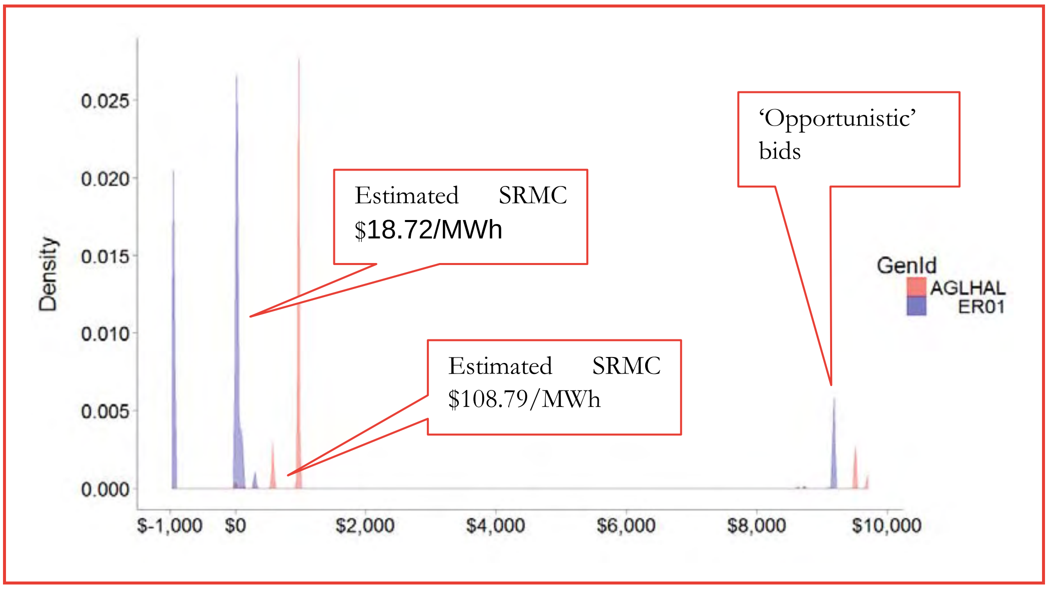
13 See Tavis Consulting, *VoLL and the cumulative price threshold: Issues paper,* prepared for the National Electricity Code Administrator (NECA) Reliability Panel, December 2003, available here (Tavis report), p.23.

14 SRMC estimates have been taken from: ACIL Tasman, *Fuel resource, new entry and generation costs in the NEM*, April 2009.

By contrast, being a peaking plant, AGLHAL bid virtually none of its capacity at very low prices. The majority of its capacity was bid in the $500/MWh to $1,000/MWh range. A smaller amount was also opportunistically bid at prices just below the current MPC of $10,000/MWh.

Figure 2: Example of 5-minute quantity-price bids (baseload coal)



Source: Frontier Economics

Expected changes to bidding behaviour

In order to understand the potential impact of a higher MPC on spot prices, it is necessary to understand how bidding behaviour is likely to change *after* an increase in the MPC.

An increase in the MPC could both *directly* and *indirectly* encourage generators to change their bidding strategies:

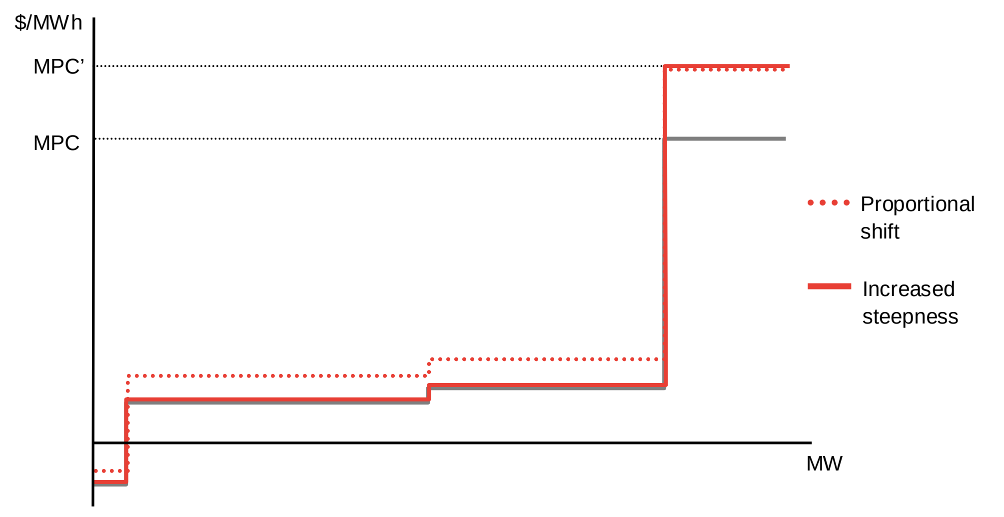
- Directly: an increase in MPC could increase the 'payoff' for a generator from exercising transient market power – see section 6.2 below
- Indirectly: an increase in MPC could reduce generators' willingness to enter derivative contracts – see section 5.2 below. To the extent this leads to generators being less hedged against spot price volatility, this could also encourage the exercise of transient market power.

Estimating the strength of these incentives and the resulting market outcomes would require a complex modelling exercise that is beyond the scope of the present analysis.

In the absence of such a modelling exercise, it is reasonable to presume that generators would not necessarily increase the price of <u>all</u> their offers in the same proportion following an increase in the MPC. At least in the short term, generators could be expected to:

- increase the price of their opportunistic offers to reflect the increased MPC
- not change the price at which they offer the majority of their capacity.

Figure 3: Potential impact of higher MPC on offer curves



Source: Frontier Economics

Assuming that participants respond to a higher MPC in this way, the offer curves offered by generators will likely become ‘steeper’ rather than simply shifting proportionately upwards. That is, offer prices are likely to increase for a relatively small proportion of capacity rather than for all levels of capacity. The alternatives are compared in Figure 3 – we would expect to see *ex post* bids reflecting the solid red line rather than the proportional shift represented by the dotted red line.

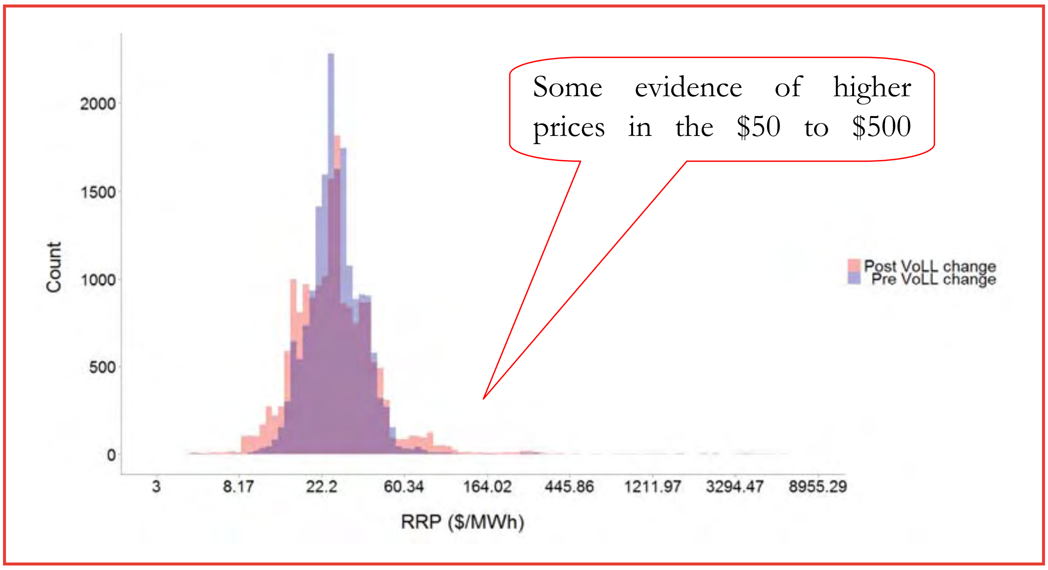
The consequence of steeper (rather than proportionately up-shifted) offer curves is that while a higher MPC is likely to increase both the frequency and level of extreme prices, it is unlikely to significantly affect prices at other (particularly off-peak and shoulder) times. This, in turn, implies that average spot prices should increase by *proportionately less* than any increase in the MPC.

On the other hand, it may be that this presumed response by generators understates the effect of raising the MPC on generators’ incentives to exercise transient market power. This could occur if raising the MPC significantly ‘tips the balance’ in favour of greater economic withholding in the manner set out in Stoft’s stylised example (see section 6.3 below). To the extent this occurs – and it is impossible to tell in the absence of undertaking a strategic modelling exercise – the average spot price could conceivably rise by *proportionately more* than the increase in the MPC.

2.3.2 Impact of previous VoLL increase

This section examines what happened to spot prices before and after the previous VoLL increase from $5,000/MWh to $10,000/MWh on 1 April 2002.

Figure 4: Distribution of NSW spot prices (pre- and post- VoLL change)



Source: Frontier Economics

Figure 4 sets out a distribution of NSW prices for one year pre (ie 1 April 2001 to 31 March 2002) and one year post (ie 1 April 2002 to 31 March 2003) the VoLL change. Analogous charts for Queensland, South Australia and Victoria[15] are contained in Appendix A.

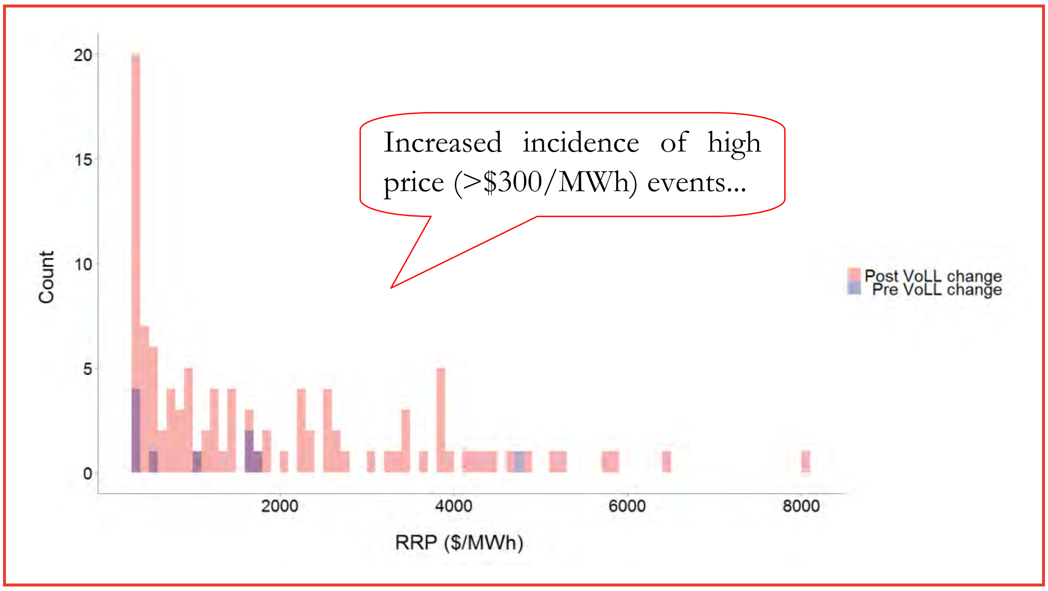
Figure 4 and Figure 18 to Figure 20 provide some evidence of increased price volatility following the increase in VoLL from $5,000/MWh to $10,000/MWh. It appears that the spread of spot prices in the year immediately following the increase in VoLL was greater than in the year immediately preceding the increase.

Accompanying this increased spread of prices was an increase in the number of high price (greater than $300/MWh[16]) events, as is evident from Figure 5 (NSW) and Figure 21 to Figure 23 of Appendix A (Queensland, South Australia and Victoria).

15 Tasmania had yet to join the NEM at the time when VoLL was last revised.

16 We discuss in more detail why $300/MWh is an appropriate cut off in section 2.3.3.

Figure 5: Distribution of NSW spot prices > $300/MWh (pre- and post- VoLL change)



Source: Frontier Economics

These price distributions provide some evidence of increased:

- price volatility and
- incidence of high price events,

following the last increase in VoLL.

However, drawing firm causal conclusions from a historical comparison is not possible given the multitude of additional factors (such as weather, demand and outages) that are likely to have changed between the two time periods of interest.

Therefore, while both the volatility of prices and the incidence of high price events appear to have increased in the period after VoLL was increased, the cause of these changes cannot be attributed solely to the increase in the market price cap.

2.3.3 Scaling historical prices

Methodology and caveats

The discussion above suggests that a higher MPC could be expected to increase average long term spot prices primarily through higher-priced opportunistic offers. In the absence of market dispatch modelling we have sought to derive the potential broad impact of higher MPCs on average spot prices.

In essence we motivate the following 'what if' analysis by posing the following thought experiment: assuming that the conditions that prevailed in a given historical year when the MPC was set at $10,000/MWh were repeated for a higher MPC, and assuming that participants reacted to this higher MPC by homogeneously scaling their offers above a certain 'extreme' price (as per the solid red line in Figure 3), what would be the expected impact on historical average prices for that year?

There are several key caveats on this analysis:

- Performing a comparative-static analysis of historic prices where it is assumed that only the MPC changes implicitly abstracts from both the short-run (strategic) and long-run (investment) impacts of a higher MPC – both of these effects would be captured in a more detailed market modelling exercise.
- The analysis is based on an arbitrary determination of a price above which participants' offers are assumed to be scaled up in response to the higher MPC.
- The analysis is not forward looking, and should in no way be considered a forecast, estimate or projection of the expected uplift in future wholesale prices under different MPCs.
- The analysis ignores other factors that would affect future demand and supply, and hence spot prices, but which are distinct from an increased MPC, such as load growth, investment and government polices (eg CPRS).

Selecting 'extreme' prices

In performing this analysis, we have chosen to restrict the scaling up of historical spot prices to those historical prices in excess of $300/MWh. We have chosen to scale only prices greater than $300/MWh for two reasons:

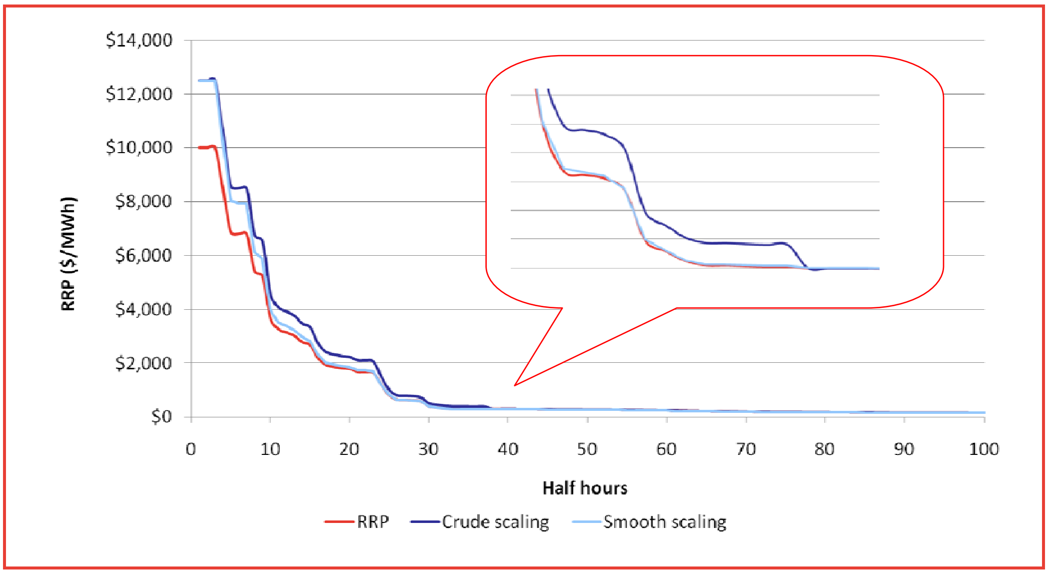
- $300/MWh is an approximate upper-bound of the highest generator SRMC in the NEM. As discussed in section 2.3.1 above, generators tend to offer the majority of their capacity to the market at prices broadly reflective of their SRMC. Remaining capacity is then offered at prices far exceeding SRMC – it is these offers that will most likely be affected by a higher MPC.
- the majority of cap contracts sold by generators in the NEM are struck at prices around $300/MWh. For this reason, there tends to be a large concentration of market prices just below $300/MWh. These prices are set by generators who have sold cap contracts and who are trying protect their positions by keeping prices below the strike price of these contracts.

One 'crude' way of scaling up historical prices in excess of $300/MWh would be to multiply each price by the ratio of the new MPC to the existing MPC. For example, in the case of a MPC of $12,500/MWh, a crude scaling approach would involve scaling all prices above $300/MWh by 1.25. However, we have chosen to apply a 'smooth' scaling approach whereby historic prices above $300/MWh are scaled up in accordance with the distance of each price from the MPC. This helps achieve a smooth 'glide path' of scaled prices. For example, to reflect a MPC of $12,500/MWh, we scale up prices above $300/MWh as follows:

- for prices close to \$10,000/MWh we assume a scaling factor approaching 1.25
- for prices close to \$300/MWh we assume a scaling factor approaching 1.

While by no means ideal, we consider this is a more sensible approach than simply creating a step-change break in the post-scaled price-duration curve. Figure 6 demonstrates this approach for 2008/9 NSW prices.

Figure 6: Scaling methodology for MPC of \$12,500/MWh



Source: Frontier Economics

Results

The results of the scaling analysis for NSW are presented in Figure 7 and Figure 8. Analogous results for Queensland, South Australia, Tasmania and Victoria are presented in Figure 24 to Figure 31 in Appendix A. Several observations can be made based on these results:

- The choice of historical year for which prices are scaled drives the extent to which historical average prices increase. Historical years with a large proportion of extreme prices (above \$300/MWh) – in the case of NSW, these are 2004/5 and 2005/6 – have a far larger average price impact than years with only a few extreme prices.
- Average prices increase at an increasing rate over the range of MPCs.
- The variance of potential uplift in historical average prices increases at higher levels of MPC. This is due to the distribution of prices above \$300/MWh being different in different years. For high levels of MPC, a year with a significant number of extreme prices experiences a far greater uplift in average prices than a year with a lower number of extreme prices.

- As expected, due to the strong correlation between demand and price, the impact on demand-weighted average prices is larger than the impact on time-weighted average prices for any given MPC and year.[17]

Figure 7: Time-weighted average price increases (NSW)

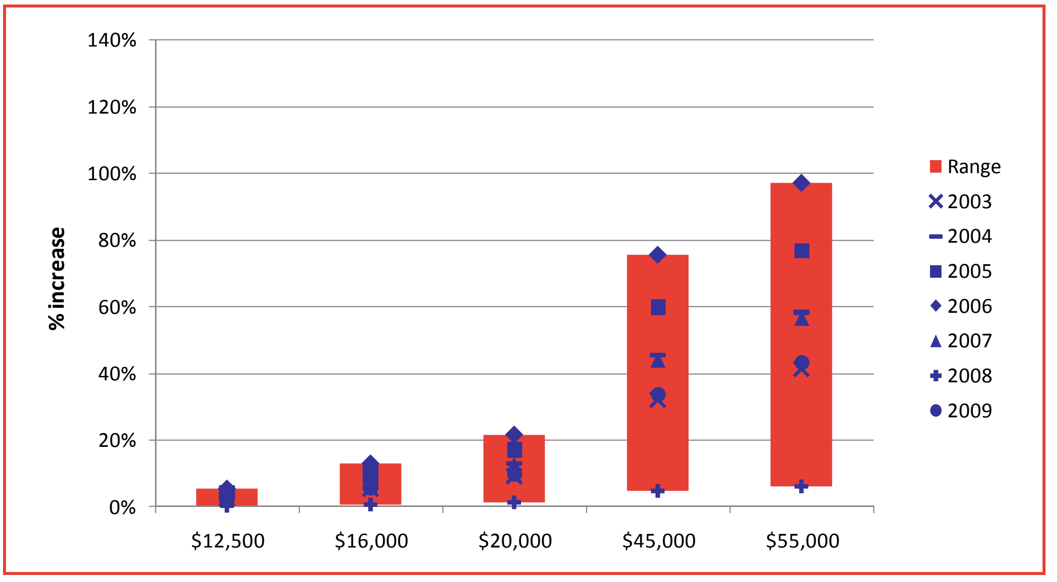
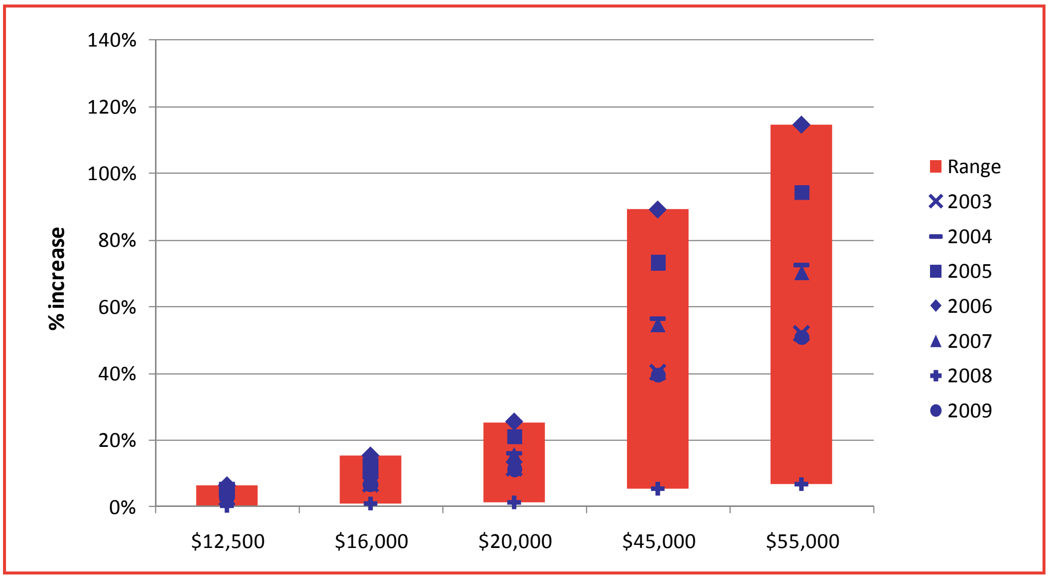


Figure 8: Demand-weighted average price increases (NSW)

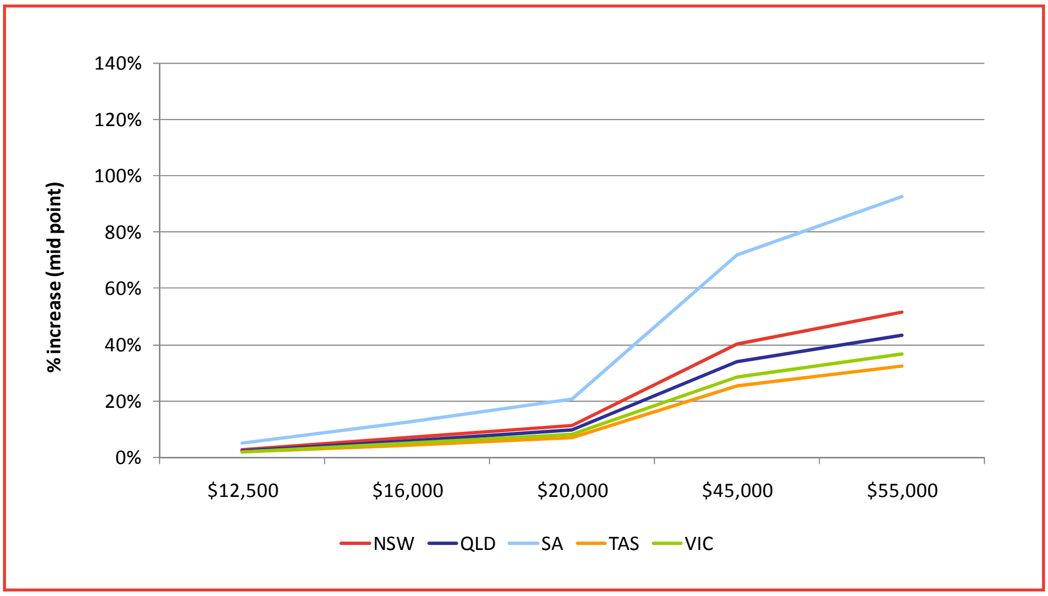


Source: Frontier Economics

17 Demand-weighted average prices weight each trading interval price by demand in the corresponding half-hour while time-weighted average prices weight each trading interval price equally.

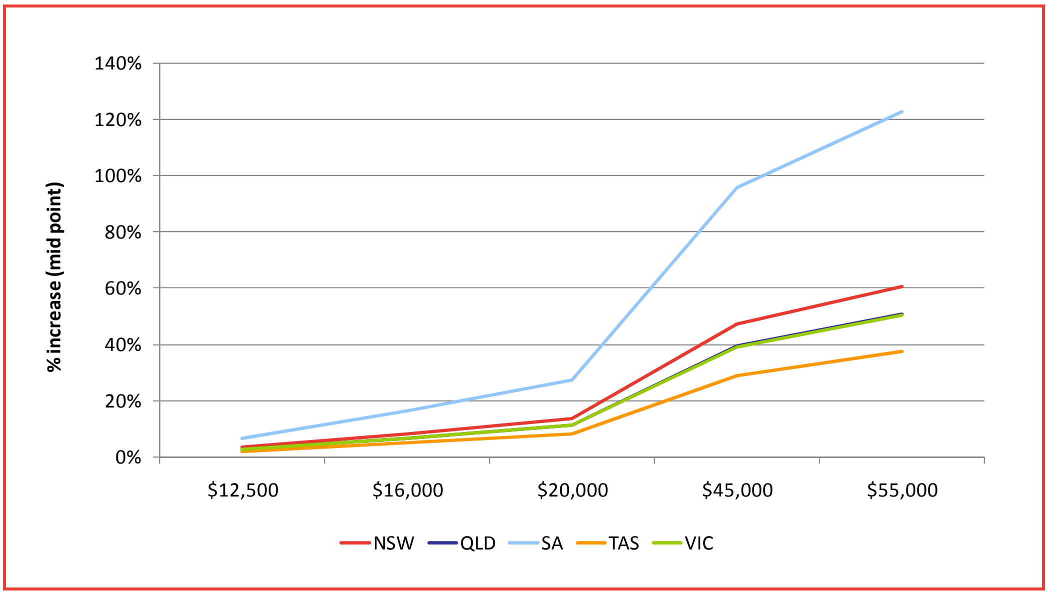
Figure 9 and Figure 10 present mid-point time- and demand-weighted average price increases for each NEM region. These increases are the mid-point estimates of the ranges presented in Figure 7, Figure 8 and Figure 24 to Figure 31.

Figure 9: Mid-point time-weighted average percent increase (by region)



Source: Frontier Economics

Figure 10: Mid-point demand-weighted average percent increase (by region)



Source: Frontier Economics

The mid-point estimate of historical average price increases for different levels of MPC varies according to the peakiness of prices in each region. The peakiness of prices is in turn driven by the peakiness of load. As can be seen from Figure 9 and Figure 10:

- Average price increases for South Australia are larger than for all other regions at all levels of MPC, due mainly to the peakiness of South Australian load and hence prices.
- Tasmania has the lowest average price increases, due to the relatively flat nature of Tasmanian load and rarity of extreme prices.
- NSW, Queensland and Victoria experience average price increases between these two extremes.

We conclude by reiterating our caveats that this analysis is an assessment of possible changes to historical average prices, and do not purport to be predictions of future spot price changes due to increases in the MPC.

Key observations

In an energy-only market such as the NEM, investors in generation capacity are required to recover their total costs through the spot market or derivative contracts settled against spot market outcomes. Using our proprietary model, WHIRLYGIG, we modelled likely generation investment patterns with different levels of the MPC. In general, a higher MPC was associated with more investment in generation capacity, particularly OCGT peaking capacity.

We also considered the potential impact of a higher MPC on spot prices. In principle, a higher MPC should increase generators' incentives to directly or indirectly exercise transient market power. Properly understanding how these influences could play out in practice would require a more complex modelling exercise than we have had time to undertake. Nevertheless, we would expect that while generators would continue to offer the bulk of their capacity to the market at or about their SRMC, on the margin, they would increase the price of their offers above $300/MWh. This is approximately at the top of peaking generators' SRMCs in the NEM and about the level of cap strike prices.

Assuming that generators only increased the price of offers above $300/MWh in response to a higher MPC, we hypothesised how historical average spot prices in each region might have been different with higher MPCs. We found that the results varied greatly according to the relevant year for which historical prices were adjusted and that the extent and variance of average price uplift increased non-linearly with the level of MPC. We also found that the mid-point estimate of average price increases for different MPCs varied according to the peakiness of prices – and hence load – in each region.

3 Demand side response

This section examines the extent to which raising the MPC and the CPT is likely to attract additional demand side response (DSR). In its *Review of Demand-Side Participation in the National Electricity Market*, the AEMC defined demand-side participation as:

> [the] ability of consumers to make decisions regarding the quantity and timing of their energy consumption which reflects their value of the supply and delivery of electricity."[18]

In the context of increasing the MPC, we interpret DSR to mean the *real-time* response of consumers to changes in wholesale market conditions, particularly the spot price. Put another way, it is the extent to which consumers are willing and able to respond to changes in the market spot price of electricity more or less immediately by reducing their electricity demand. We have deliberately not interpreted DSR to mean a longer term reduction in the rate of load growth due to higher prices.

As discussed below, high demand-side responsiveness provides numerous benefits to electricity markets, including reducing the need for a high MPC (or the MPC altogether) and mitigating generators' incentives to exercise transient market power. In this way, high demand side responsiveness can promote economic efficiency.

Raising the MPC could promote additional DSRs in one or both of two ways:

- An increase in DSR for a given elasticity[19] – to the extent that a rise in the MPC increases the potential upper range of wholesale prices, a higher MPC could increase the incentive of loads to reduce demand (in MW) at those times to avoid the higher prices.
- An increase in DSR caused by a larger elasticity – to the extent that a higher MPC encourages loads to invest in new processes and technologies that enable consumers to respond to high prices more easily, a higher MPC could increase the responsiveness of loads to peak prices.

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18 AEMC, *Review of Demand-Side Participation in the National Electricity Market, Final Report*, 27 November 2009 (AEMC DSP Review Final Report), p.2.

19 Elasticity broadly refers to the responsiveness of demand to price. However, different studies estimate different types of price responsiveness. For example, own-price elasticity for a given commodity (eg peak period demand) indicates how much the quantity demanded for that commodity changes in response to a change in its price. Cross-price elasticity indicates the extent to which demand for a certain commodity (eg peak period demand) changes due to a change in the price of a substitute (such as the off-peak period price). When demand and prices are expressed in relative terms (eg demand for a given commodity relative to demand for a substitute) the estimated elasticity is referred to as the substitution elasticity. In general, the larger an estimate of elasticity (in absolute terms), the greater the sensitivity of demand to price.

Below we examine the benefits of engaging in DSR in the NEM before exploring how a higher MPC is expected to affect DSR.

3.1 Benefits of DSR in the NEM

3.1.1 Benefits to relevant participant

A participant's underlying incentive to engage in DSR reflects basic microeconomic theory: consumers will consume up to the point where the marginal benefit from consumption equals the marginal cost. In this respect, electricity should be the same as any other commodity. Just as there will be a point at which a consumer will not want to buy any more apples at the going price, so should there be a point on a hot day when a consumer would prefer to endure a warmer home than consume and pay for the electricity needed to run their air conditioner.

However, demand in electricity markets is typically very inelastic (unresponsive) to wholesale prices, at least in the short term. This is primarily because:

- electricity is an essential input to the full functioning of many parts of modern life
- there are limited direct price signals to customers since retailers do not generally offer real time tariffs to customers, and the real-time metering infrastructure to do so is not widespread.

Even when retailers are themselves settled on the basis of the real-time consumption of their customers, retailers generally do not offer real-time tariffs based on wholesale spot outcomes to their customers. This could reflect the asymmetric risk to the consumer of such real-time tariffs – although a consumer may save a small amount on their bills in an average year by accepting such tariffs, they face the risk that in an extreme year, their bills may be much higher than if based on a tariff determined using average prices.[20]

This means that when wholesale spot prices are extremely high (such as approaching the MPC), consumers will only save the *average* retail price by reducing their consumption instead of a retail price that reflects the *prevailing* high wholesale price. This dilution of the wholesale price signal explains why customers are less responsive to wholesale price changes than they might otherwise be.

[20] See AEMC DSP Review Final Report, p.3.

3.1.2 Benefits to the market

DSR contributes to market efficiency in the short term and the long term. In the short term, DSR can enhance allocative and productive efficiency:

- Allocative efficiency refers to resources being allocated to their highest-valued uses. A key benefit of DSR is that it involves electricity consumption for relatively low-valued uses falling at times when the cost of generating additional power may be greater than the value that some consumers derive from that power.[21] Even if the value that consumers place on electricity is greater than the marginal cost of generating that electricity, in the event of absolute supply scarcity, greater scope for *voluntary* DSR activity means that there is potentially less need for *involuntary* load shedding. In this way, DSR allows power to be curtailed first to those customers that are presumed to value electricity supply the least. If sufficient DSR is available, there may be no need for any involuntary load shedding because the market will clear at a (lower) price determined by the intersection of supply with (voluntary) demand. At the limit, if all consumers in the market can express their willingness to pay for electricity and respond accordingly, there may be little need for a MPC at all. Even some amount of DSR can help overcome the need for spot prices to rise steeply at times of supply scarcity.
- Productive efficiency refers to outputs being produced at least cost. DSR may enhance productive efficiency to the extent that it deters generators from exercising transient market power (discussed further in section 6 below). In brief, DSR can reduce the 'payoff' from generator withholding strategies because the spot price will be less sensitive to the removal or repricing of small amounts of generation capacity from the dispatch merit order (see Figure 11 below). The exercise of transient market power can harm productive efficiency if it involves generators with relatively low SRMCs (such as coal baseload plant) withholding their output and being displaced by generators with higher SRMCs (such as gas turbines).

In the longer term, DSR should promote dynamic efficiency by encouraging a more efficient quantity and mix of investment in new generation and network augmentation. For example, if DSR allows low-valued electricity consumption to be curtailed at peak times, thereby limiting price spikes, this will discourage the entry of new generation plant (particularly peaking plant) to supply those low-valued uses. The resources not expended in developing such plants can be deployed elsewhere in the economy where they should produce more highly-valued outputs. Similarly, DSR could reduce the need for network augmentation to meet peak demand, again allowing the saved resources to be utilised

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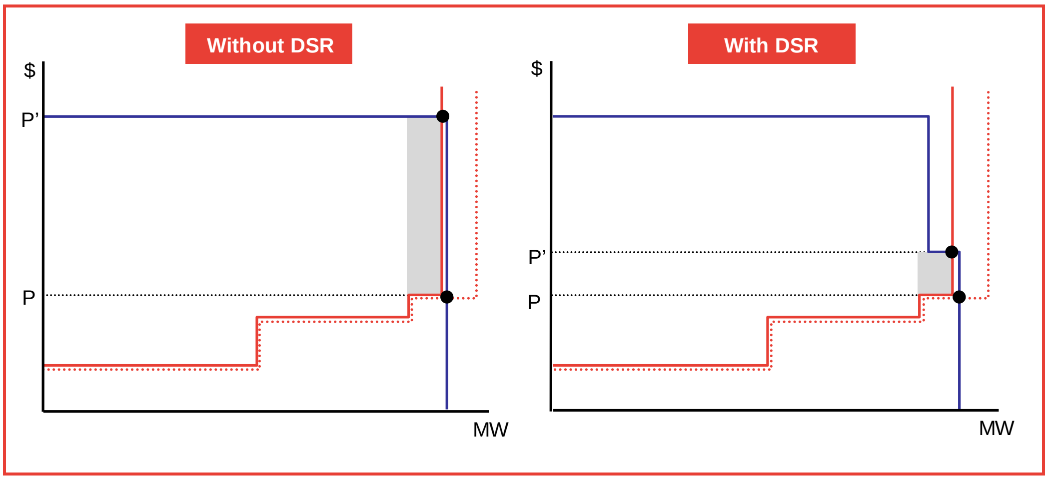
21 AEMC DSP Review Final Report, p.12.

elsewhere.[22] A reduction in spot price volatility should also reduce trading risks to participants (see section 5 below), which should reduce the long term costs of serving (the remaining) load.

Figure 11: Incentive to exercise transient market power with and without DSR



Source: Frontier Economics

Strbac also notes a number of other benefits from DSR, including:

- increasing the amount of distributed generation that can be connected to the existing distribution network infrastructure
- relieving voltage-constrained power transfer problems
- relieving congestion in distribution substations
- simplifying outage management and enhancing the quality and security of supply to critical-load customers
- providing corresponding carbon reduction.[23]

3.1.3 Forms of demand side response

As noted above, DSR requires that consumers are exposed to price signals that give them incentives to curtail their demand at times that supply is scarce in relation to demand. This may occur in two ways in the NEM:

- direct wholesale price exposure through wholesale market participation or retail contracts
- consumers contracting with retailers for load shifting or curtailment.[24]

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22 AEMC DSP Review Final Report, p.4.

23 Strbac, G., "Demand side management: Benefits and challenges", *Energy Policy* 36 (2008) 4419-4426.

24 AEMC DSP Review Final Report, pp.3-4.

This section will also consider embedded generation, a form of load curtailment that can be used as a DSR.

Direct wholesale price exposure

Consumers can gain direct exposure to the wholesale market by registering as a scheduled load. This allows consumers to bypass retailers and purchase electricity directly from the wholesale market. Consumers are able to bid to purchase energy up to their marginal benefit and reduce or stop consumption if the spot price exceeds this level. This method of participation is extremely rare, with only three customers taking part in late 2008,[25] and none presently appearing on AEMO's list of scheduled loads.[26] This is because it is only worthwhile for large loads that can manage intermittent supply and have systems that allow them to turn off easily.

An alternative method to gain exposure to the wholesale market price is to contract with a retailer to pass-through the spot price. According to the AEMC's DSP Review, one example is Adelaide Brighton Ltd, which has been exposed to wholesale spot prices through its retail contract and has managed to save a significant proportion of its bill in this way.[27] However, this method of participation is also fairly rare due to the costs and risks associate with exposure to the wholesale price (see section 3.2 below).

Price exposure from contracting and other incentive schemes

An alternative method for taking exposure to the wholesale market, used by most consumers engaging in DSR, is to enter into contracts incorporating arrangements for shifting or curtailing consumption.[28] For example, a retailer may offer to pay a customer to reduce its load at times of high prices.[29] For the consumer to enter such arrangements, this payment must be large enough so the avoided energy charge plus the payment exceeds the foregone benefit from consuming electricity. The cost for the retailer would be the fee paid plus the foregone retail margin on the energy not consumed while the benefit would be the avoided costs of purchasing energy to supply the customer, as well as any reduction in the wholesale price resulting from the lower demand (to the extent the retailer is unhedged and is exposed to the spot price in respect of its other customers).

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25 Energy Response, *AEMC DSP Review Stage 2 – Supplementary Submission*, 15 December 2008, p.5.

26 See AEMO, *NEM Registration & Exemptions List*, available here, accessed 11 March 2010.

27 AEMC DSP Review Final Report, p.3. Such contracts often come with gain or loss caps to limit risk.

28 AEMC DSP Review Final Report, p.4.

29 Contracts may be entered into individually, or via aggregators who bring together several small loads into one large load.

Embedded generation

Consumers can also engage in DSR through the use of embedded generators. These plant allow consumers to create their own supply if it is cheaper or otherwise more beneficial than drawing power from the NEM. Generators of this type can range from gas to oil to solar. The most prominent example in the NEM is the 176 MW Smithfield combined cycle gas turbine plant now operated by Marubeni Australia Power Services.[30] Smithfield is registered as a non-market scheduled generator, meaning that its entire output is purchased by the local market customer and is not traded in the NEM. There are numerous non-scheduled generators in the NEM whose output is also consumed locally.

3.1.4 Existing quantum of demand side response

At present, DSR as a proportion of total load is still a relatively minor feature of the NEM. In particular, as noted above, direct demand-side participation as a scheduled load in the NEM has been and remains extremely limited.

For its Electricity Statement of Opportunities (ESOO), AEMO, in conjunction with the Load Forecasting Reference Group (LFRG), surveyed network service providers, aggregators and market customer to gather the extent of DSR available in each region and in the NEM overall. This survey showed a total of 754 MW of DSR available. Of this, 195MW was 'committed', meaning it had a high probability of being deployed in extreme circumstances, and 559 MW was uncommitted, meaning it had a lower probability. In addition, AER investigations have identified several apparent demand reductions in response to high prices, including of up to 350 MW in NSW when prices reached $8,800/MWh on 15 January 2009.[31]

3.2 Impact of an increase in the MPC and CPT

In principle, we would expect current levels of DSR to increase if the MPC were increased. This is because, all else being equal, the benefits for both customers and retailers of undertaking DSR increase as the MPC rises. As noted above, this could occur through one or both of two ways:

- an increase in DSR for any given set of elasticities of electricity demand
- an increase in DSR due to the impact of a higher MPC on the price elasticity of electricity demand.

These paths of influence are discussed below.

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30 See AEMO, *NEM Registration & Exemptions List*, available here, accessed 11 March 2010.

31 AEMC DSP Review Final Report, p.5.

3.2.1 Increased demand side response for a given elasticity

The extent of DSR will be influenced by the level of the MPC relative to the distribution of the values of consumers' benefits of electricity consumption. If consumer valuations of electricity vary significantly and the market price is capped below the level of at least some consumers' valuations of electricity, an increase in the MPC would provide incentives for some degree of additional DSR. In principle, a higher MPC should, to the extent wholesale prices are passed-through to consumers, encourage DSR from consumers whose valuation of electricity is above the previous MPC but below the new MPC. As noted in section 3.1.2 above, this should enhance allocative and productive efficiency.

In its Final Determination on VoLL in 2000, the ACCC accepted the conceptual link between a higher MPC and incentives for increased DSR. However, the ACCC expressed concern regarding the barriers to DSR that could prevent a higher VoLL encouraging more DSR. These barriers included:

- reluctance of large customers to enter interruptible load contracts with retailers or to take wholesale spot exposure
- lack of time of use (interval) metering or retail competition for small customers.[32]

However, in its recent DSP Review, the AEMC concluded that "barriers to DSR **do not exist** in a number of significant areas."[33] (emphasis added) In particular, the AEMC referred to the deployment of smart meters and smart grids as an ongoing development that was helping to address the lack of suitable metering technologies for small customers.[34] The AEMC also commented that while there were minor barriers to the aggregation of loads for the provision of market ancillary services, the costs of participation in the wholesale market should not be regarded as a barrier to DSR, as such requirements are necessary for the secure and reliable operation of the power system.[35] Perhaps most crucially, the AEMC found that:

> …the major deterrent to [retailers contracting with customers for DSR] is the price being sought by customers to provide the service. When developing a financial portfolio to manage risk, a retailer has a choice between generation options and demand-side options. The retailer has a financial incentive to choose the cheapest option that achieves their desired outcome. If the price being sought for [DSR] is higher than the price for a generation option, or any other alternative, a retailer will pick the generation option and this will be an efficient decision. Therefore, to the extent that

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32 ACCC, *VoLL, Capacity Mechanisms and Price Floor, Determination*, 20 December 2000, pp.41-42.

33 AEMC DSP Review Final Report, p.2.

34 AEMC DSP Review Final Report, Box 2.1, p.15. See also below on increasing DSR through changing elasticity.

35 AEMC DSP Review Final Report, p.55.

> retailers are perceived to not be using enough [DSR], we do not consider that this is due to any barriers in the Rules but is most likely driven by the high price of [DSR] services relative to alternatives.[36]

The AEMC did find barriers to demand-side participation in a variety of areas, including the network regulatory arrangement,[37] distribution network planning,[38] the technical standards for embedded generation[39] and in AEMO's reserve energy trading activities.[40] However, these areas are not relevant to the normal real-time operation of the wholesale market and so would not reduce the potential for a higher MPC to encourage more DSR.

In our view, a higher MPC could – at the margin – change the relative value of DSR versus alternative sources of supply and consequently lead to an increase in DSR contracting between retailers and customers. The empirical literature concerning the relationship between electricity prices and DSR can be loosely classified according to the type of customer in focus – residential or business customers – although small business customers are often examined along with residential customers.

Residential customers

At least in relation to smaller customers, a higher MPC may not induce a great deal of additional DSR. In a recent survey article, Faruqui and Sergici[41] reviewed the outcomes of 15 dynamic pricing experiments, including EnergyAustralia's pricing trial in 2005. While these experiments were designed to understand the benefits of real-time 'smart' metering infrastructure (discussed further in section 3.2.2 below), the results also provide valuable insight into the potential demand response of smaller customers to higher retail tariffs driven by a higher MPC.

Summarising the evidence across the 15 trials, Faruqui and Sergici found that demand response impacts varied widely, due to differences in the observed tariff designs, the use of enabling technologies (such as programmable thermostats), ownership of central air conditioning and study sample design.[42]

The trials Faruqui and Sergici examined all involved 'critical peak' retail tariffs of less than ten times off-peak tariffs (and only about 3 to 5 times control reference

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36 AEMC DSP Review Final Report, pp.64-65.

37 AEMC DSP Review Final Report, p.24.

38 AEMC DSP Review Final Report, pp.36-40.

39 AEMC DSP Review Final Report, p.45.

40 AEMC DSP Review Final Report, p.70.

41 Faruqui, A. and S. Sergici, *Household Response to Dynamic Pricing of Electricity – A Survey of the Experimental Evidence,* 10 January 2009 (Faruqui and Sergici), available here.

42 Faruqui and Sergici, pp.40-41.

'anytime' averaged tariffs).[43] Given that the current MPC of $10,000/MWh is already approximately 200 times average wholesale prices (of about $50/MWh), the DSR benefits of increasing this ratio further in relation to smaller customers are difficult to predict.

In examining the likely level of DSR for different critical peak prices, Faruqui and Sergici drew from the results of the California Statewide Pricing Pilot. Using the Price Impact Simulation Model (PRISM) that was developed during that trial, Faruqui and Sergici estimated the DSR for residential customers with and without central air conditioning (CAC).

They estimated that raising the peak retail tariff from the anytime averaged tariff of $US0.13/kWh to:

- $US0.23/kWh would lead to:
  - Customers <u>with</u> CAC reducing critical peak demand by 6.3%
  - Customers <u>without</u> CAC reducing critical peak demand by 2.3%
  - The 'average' customer reducing critical peak demand by 3.8%
- $US0.43/kWh would lead to:
  - Customers <u>with</u> CAC reducing critical peak demand by 13.1%
  - Customers <u>without</u> CAC reducing critical peak demand by 4.7%
  - The average customer reducing critical peak demand by 7.9%
- $US0.83/kWh would lead to:
  - Customers <u>with</u> CAC reducing critical peak demand by 20.2%
  - Customers <u>without</u> CAC reducing critical peak demand by 7.2%
  - The average customer reducing critical peak demand by 12.3%
- $US1.53/kWh would lead to:
  - Customers <u>with</u> CAC reducing critical peak demand by 26.7%
  - Customers <u>without</u> CAC reducing critical peak demand by 9.5%
  - The average customer reducing critical peak demand by 16.3%.[44]

See Figure 12 below for a more comprehensive set of results. These estimates suggest that progressively increasing the MPC from the existing level – and assuming this increase will be passed through to customers – is likely to yield diminishing additional amounts of DSR by residential customers.

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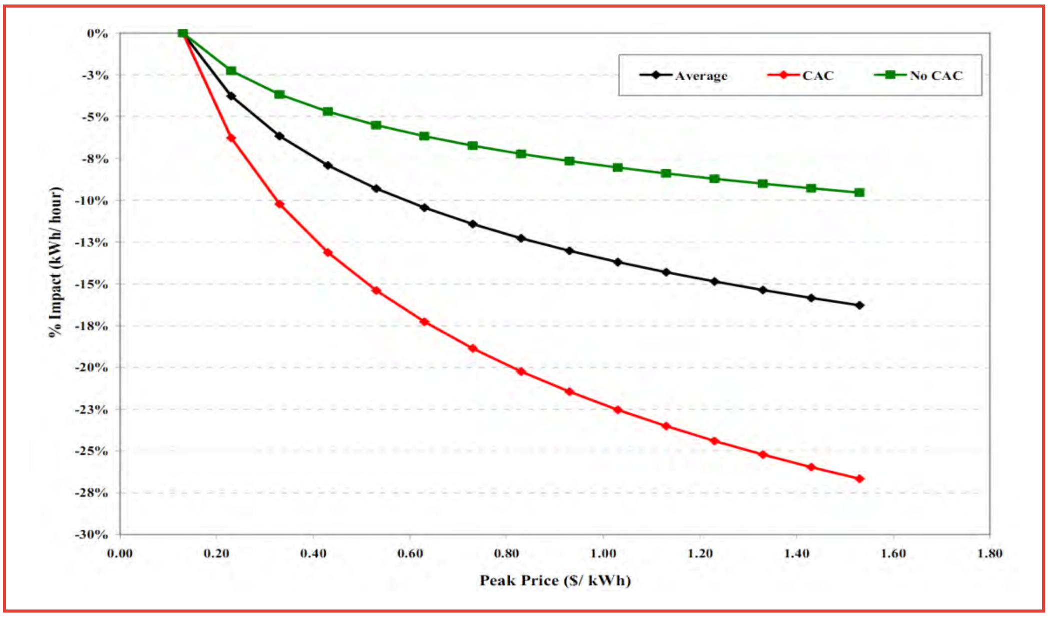
43 See Table 31, pp.47-48.

44 Faruqui and Sergici, Table 32, p.45.

Figure 12: California residential DSR on critical days



Source: Faruqui and Sergici, Figure 2, p.45.

Faruqui and Sergici also reported on the preliminary results from the EnergyAustralia pricing trial. These results showed that residential customers reduced their peak consumption by approximately:

- 24% for 'high' tariff rates ($2+/kWh, equivalent to $2,000/MWh)
- 20% for 'medium' tariff rates ($1+/kWh, equivalent to $1,000/MWh).[45]

The results likewise suggest that although increasing the MPC is likely to generate some incremental residential DSR benefits, these benefits are likely to be relatively small.

Business customers

For business customers, the evidence is more mixed. The results of the EnergyAustralia trial reported by Faruqui and Sergici found that the response of small and medium businesses to time of use (ToU) tariffs was less than the response of residential customers, although these results were not statistically significant.[46]

Braithwaite and O'Sheasy analysed data from participants in Georgia Power's real-time pricing (RTP) program, the largest in the country.[47] The authors

45 Faruqui and Sergici, p.35.

46 Faruqui and Sergici, pp.34-35.

47 Braithwaite, S.D. and M. O'Sheasy. 2002. "RTP Customer Demand Response — Empirical Evidence on How Much Can You Expect," in Faruqui and Eakin (eds), *Electricity Pricing in Transition*, Boston, MA: Kluwer Academic Publishers.

estimated own-price elasticities for seven different business customer segments and examined differences across hourly price levels. Most customer segments exhibited larger price elasticities at higher prices. The most responsive customer segment was a group of very large industrial customers (peak demand > 5 MW) who, in exchange for slightly lower base rates, had opted to receive notification of hourly prices on an hour-ahead (rather than day-ahead) basis. This group exhibited a price elasticity of –0.18 to –0.28 across the range of reported prices ($US0.15/kWh to $US1/kWh), which was double the elasticity of any other group. The least responsive customer segments, consisting of smaller commercial and industrial customers that neither had onsite generation nor had previously participated in the utility's curtailable rate, exhibited price elasticities of –0.06 or lower at all price levels.

A study by Hopper et al examined the experience of 119 large commercial and industrial customers at Niagara Mohawk Power Corporation that have faced day-ahead electricity market prices as their default tariff since 1998.[48] The study found that the load-weighted average elasticity of substitution for the 119 customers that faced hourly prices was 0.11.[49] This means that a doubling of the peak to off-peak price ratio, other factors held constant, would result in an 11% reduction in the ratio of peak to off-peak electricity use. In terms of aggregate load response, these 119 customers could be expected to reduce their combined summer peak demand by about 50 MW (or 10%) at a peak/off-peak price ratio of 5:1, the highest observed during the study period. This corresponded to a peak price of almost $US750/MWh.

3.2.2 Increased demand side response from a change in elasticity

As noted above, electricity demand is relatively inelastic with respect to its price, even for larger business customers. However, an increase in the MPC may serve to increase the price elasticity of demand, meaning a greater percentage reduction in demand for a given percentage increase in the wholesale price, other things being equal.

Stoft postulated that:

> High prices encourage price responsiveness both directly and through learning. Some loads will not find it worth curtailing their use of power until prices exceed $1,000/MWh. But, once a load has learned to respond, it may find it sensible to

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48 Hopper, N., C. Goldman, R. Bharvirkar and B. Neenan, "Customer Response to Day-Ahead Market Hourly Pricing: Choices and Performance", *Utility Policy*, Volume 14, Issue 2, pp.126-134 (Hopper et al), unofficial version available here.

49 Hopper et al., Table 2.

> respond to price increases that would not trigger a response before the necessary control equipment is installed and such responses become routine.[50]

Responding to high wholesale prices for the first time may be costly due to operational practices that need to be adopted or capital equipment that needs to be installed. However, higher electricity prices associated with an increased MPC may make such investments cost effective, allowing future DSR to be achieved more cheaply. This would be expected to result in a larger DSR at any given level of wholesale spot prices.

By contrast, the Energy Users Association of Australia (EUAA) has argued that the higher price and risk arising from by a higher MPC may perversely serve to *decrease* demand response. This view is based on the assertion that the higher price risk in the wholesale market will dissuade consumers from exposing themselves to the wholesale market price.[51] This view has some support in the literature.[52]

While plausible, we note that the vast majority of electricity consumers achieve DSR through contractual or generation options, where it is possible to manage higher price risks while still benefiting from DSR. We would expect that any negative effect of a higher MPC on DSR through direct wholesale price exposure would be more than offset by the increased incentives to undertake DSR through contractual arrangements. As such, we consider it likely that a higher MPC should lead to a net increase in real-time DSR.

A key example of investment that could support more DSR in future is the installation of interval metering systems. These systems allow for ToU electricity tariffs as well as more dynamic pricing schemes, such as real-time pricing and Critical Peak Pricing (CPP). Standard ToU tariffs involve different tariff rates (eg in c/kWh) for consumption at different times of the day, week or year. Typically, ToU tariffs will be higher for working weekday daytimes than overnight or weekend periods. CPP tariffs involve retailers having the ability to declare up to a defined maximum number of critical peak days in a year on which peak time tariffs are much higher than normal peak ToU tariffs. Therefore, dynamic tariff schemes such as CPP are capable of exposing customers to more real-time cost-reflective tariffs and thus are more suitable for promoting real-time DSR than ordinary ToU rates.[53] Other similar developments may include direct load control

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50 Stoft, S., *Power System Economics, Designing Markets for Electricity*, IEEE Press 2002, pp.118-119.

51 EUAA, *EUAA Member Demand Side Participation (DSP) Experiences and Response to AEMC Review of DSP in the National Electricity Market- Stage 2 Issues Paper*, November 2008, available here, p.12.

52 Hopper, N., C. Goldman, R. Bharvirkar and B. Neenan, Customer response to Day-Ahead Market Hourly Pricing: Choices and Performance, Energy Analysis Department, Ernest Orlando Berkeley National Laboratory,

53 Only real time pricing actually exposes consumers to the real price, and so creates real time price response. TOU and CPP tariffs are set before and as such technically do not create real time demand response. However, if the tariffs are chosen well, the results are fairly similar, decreasing

and interruptible load contracts facilitated by smart networks or thermostats which are programmed to change level based on market demand.[54]

A higher MPC and consequent expectations of higher peak wholesale prices and price risk could work to encourage privately-driven investment in new technologies such as interval metering or direct load control. For example, retailers – seeing the benefits that lower peak demand could bring – could negotiate with their customers and distributors to install 'smart' interval meters and apply CPP tariffs for mutual benefit. To the extent this occurs, the higher MPC would be responsible for increasing the price responsiveness of demand.

However, in the NEM, responsibility for decision-making over the implementation of these technologies has increasingly been assumed by regulators and policy-makers rather than market participants. For example, in 2006, the Victorian Government approved a distributor-led rollout of interval meters in that State, with cost recovery guaranteed through the distribution regulatory pricing arrangements.[55] Decisions to 'roll out' interval meters in other NEM jurisdictions are also being made by jurisdictional policy-makers.[56] Further, implementation decisions have been influenced by factors unrelated to economic benefits.

Most pointedly, the Victorian Government recently halted the introduction of ToU pricing pursuant to the roll out of interval meters for equity reasons.[57] Under these conditions, an increase in the MPC may have little influence on the likelihood and timing that such technologies will be applied.

Key observations

DSR provides a number of benefits to participants and to the market as a whole. Participants can gain financially if customers agree to curtail consumption at peak times. The market as a whole can benefit from improved allocative, productive and dynamic efficiency as resource allocation improves in both the short and long run.

Consumers can engage in DSR directly, through participation in the wholesale market trading arrangements, or indirectly, through contracting with retailers.

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demand in times of high prices and flattening load profiles. See Greening, L.A., "Demand response resources: Who is responsible for implementation in a deregulated market?", *Energy* (2010), pp.2-3.

54 Strbac, G., "Demand side management: Benefits and challenges", *Energy Policy* 36 (2008), pp.4419-4426, p.4424.

55 The Victorian Department of Primary Industries website, accessed on 23 March 2010, and Victorian Auditor-General's Report, *Towards a 'smart grid – the roll-out of Advanced Metering Infrastructure*, November 2009, available here, pp.4-5.

56 See Ministerial Council on Energy, *Smart Meter Decision Paper*, 13 June 2008, available here.

57 The Premier of Victoria's website, accessed on 23 March 2010.

Direct participation is extremely uncommon and DSR contracting is also relatively rare at the present time.

At this stage, there is simply insufficient empirical evidence to reasonably predict the quantitative impact of higher MPCs on the level of DSR in the NEM. However, several general comments can be made:

- A higher MPC should, at the margin, increase the quantum of observed DSR by residential and business consumers
- As the MPC rises, the quantum of DSR should increase at a decreasing rate.
- However, DSR from smaller customers requires investment in real-time metering or other demand management systems and a sustained political willingness to allow customers to face time-varying prices and/or automated supply interruptions. This willingness appears to be limited at the moment.

4 Prudential requirements

The NEM is a compulsory wholesale spot market. This means that all electricity generated in the NEM jurisdictions must be traded through the NEM, unless it was produced by exempt generators.

As part of its role as market and system operator, AEMO calculates the financial liability of all market participants on a daily basis and settles transactions for all trade in the NEM weekly. This involves AEMO collecting all money due for electricity purchased from the pool from market customers, and paying generators for the electricity they have produced. The spot price is the basis for all these financial transactions.[58]

In performing its settlement functions, AEMO seeks to ensure that outstanding amounts owed by or to market participants are kept at reasonable levels and are paid in a timely fashion. This promotes confidence in the financial integrity of AEMO and the NEM more generally. Under the National Electricity Rules (Rules), AEMO is empowered to require financial guarantees from market participants and may make margin calls to support those guarantees. These prudential requirements are in place in order to cover AEMO's worst case exposure to market participants. To the extent that an increase in the MPC leads to an increase in wholesale spot prices, this is likely to increase this worst case exposure, meaning that prudential requirements will need to increase, other things being equal.

In this section we consider in more detail the impact of a higher MPC on prudential requirements, particularly for electricity retailers.

4.1 Prudential requirements in the Rules

Clauses 3.3.1 and 3.3.2 of the Rules oblige market participants to comply with certain prudential requirements in respect of their participation in the spot market. In particular, the Rules require market participants to either have an acceptable credit rating or else provide AEMO with appropriate credit support from an entity with an acceptable credit rating. Such an entity is typically a financial institution but may be a parent company of the market participant with an acceptable credit rating that complies with the remaining criteria.

The prudential requirements in the Rules place an upper limit on the accumulated amount that a market participant can owe to AEMO at any one point in time. This upper limit is known as the 'Trading Limit'. In performing its regulatory

58 AEMO, *An Introduction to Australia's National Electricity Market*, December 2009, available here, p.12.

duties, AEMO monitors the outstanding amounts owed by each market participant once every business day. The 'Outstanding' amount in respect of a given market participant consists of all unsettled amounts still owed by that participant to AEMO from past and current billing periods, after having deducted existing voluntary security deposits already lodged with AEMO. The following equation explains how the Trading Limit is computed.

$$TL = CS - PM \,, \tag{1}$$

where:

TL: Trading Limit

CS: Credit Support $(CS \geq MCL)$

MCL: Maximum Credit Limit

PM: Prudential Margin

The Maximum Credit Limit is, as defined in clause 3.3.8, a dollar amount determined by AEMO on the basis of a reasonable worst case estimate of the aggregate payments for trading amounts[59] to be made by the market participant to AEMO over a period of up to the credit period (42 days for retailers). The credit support provider needs to provide Credit Support at least equal to the Maximum Credit Limit.

The Prudential Margin for a market participant is a dollar amount determined by AEMO on the basis of a reasonable worst case estimate of the aggregate of the expected trading amount[60] owing by the participant to AEMO in respect of the reaction period, which is 7 days.[61] This is to ensure that AEMO is not exposed to a prudential risk during the period of suspending a market participant from trading in the NEM.

The derivation of the 'reasonable worst case scenario' for both the Maximum Credit Limit and the Prudential Margin takes account of historical spot price volatility in the NEM. The measure of volatility employed by AEMO is the 'volatility factor', defined in section 6.1 of AEMO's Credit Limits Methodology.[62] The volatility factor is a scaling factor used in determining the reasonable worst case value of a market participant's credit liability. The calculation of the volatility factor is outlined in section 4.2.1 below.

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59 After considering any amounts reallocated under energy reallocation agreements.

60 Again after considering any amounts reallocated under energy reallocation agreements.

61 Refer to Appendix 2 Possible timeframes in the Prudential Process in *NEM Settlement Prudential Supervision Process* for explanation of why the reaction period is 7 days.

62 Available here.

To protect the financial integrity of the NEM, AEMO follows a response procedure[63] whenever a market participant's Outstanding exceeds its Trading Limit. AEMO may issue a call notice to the market participant but the market participant can act in a timely fashion to avoid this from occurring. To avoid a call notice, a market participant must do either or both of the following:

- increase its security deposit with AEMO
- secure a higher level of Credit Support.

However, if the Outstanding exceeds the Trading Limit for a longer duration than permitted by AEMO, a call notice is issued to the market participant so that the Outstanding can be lowered to levels complying with the Trading Limit. The Call Amount is determined by the higher of the following amounts as illustrated in Equation (2).

$$CA = OS - TL \quad or \quad CA = OS - TypA \tag{2}$$

where:

CA: Call Amount

OS: Outstanding

TypA: Typical Accrual of market participant (which is the level of a participant's outstanding amounts computed using average prices as at the date of the call notice)

Should the firm default on paying the Call Amount, AEMO will draw funds from the Credit Support until the funds are exhausted before making a decision about whether to suspend the market participant from the NEM.

4.2 Impact of an increase in the MPC

As discussed above, an increase in the MPC is likely to increase spot price volatility, which in turn will tend to increase the volatility factor. The higher the volatility factor, the higher will be a participant's Maximum Credit Limit and Prudential Margin, other things being equal.

For market participants, this implies (from Equation (1)), a higher financial burden. This is because for a given level of Credit Support, a higher Prudential Margin results in a lower Trading Limit. A lower Trading Limit means, in turn, an increased likelihood of a market participant exceeding its Trading Limit. This would tend to increase a participant's compliance costs as the participant would bear the risk of having to 'top up' security deposits drawn down by AEMO or potentially manage call notices more frequently.

63 Refer to Appendix 1 Flow Chart Diagrams of the Prudential Process in *NEM Settlement Prudential Supervision Process*.

A potentially more serious implication of a lower Trading Limit would be increased barriers to entry for new market participants where the Maximum Credit Limit would form a relatively large portion of their capital costs. New participants would need to convince their credit support providers to increase their Credit Support amount, for which the participant would presumably incur higher fees. This would particularly be likely to affect new entrant retailers, as retailers otherwise require relatively little capital to commence operations. To the extent an increase in prudential requirements deters new retailer entry into the NEM, the result could be reduced retail competition compared to what would otherwise prevail.

4.2.1 Impact on a participant's volatility factor

The volatility factor for each region is a ratio that is dependent on spot prices and customer loads over a period of 12 months in that region.

The formula for the volatility factor is as follows.

$$VF = \frac{Max\,(RA_t) for\ t = 1, \ldots, 365}{Ave\,(\sum_{t=1}^{365} RA_t)} \qquad (3A)$$

The numerator of the volatility factor is the highest 42-day simple rolling average[64] (RA) of the *daily value of trade*. The denominator of the volatility factor is the arithmetic average of the 42-day RAs. Hereinafter, we refer to the 42-day RAs as simply 'RAs'.

The RA computation is expressed in Equation (3B):

$$RA_t = \frac{\sum_{i=t-41}^{t} DVT_t}{42} \qquad (3B)$$

where:

RA_t = 42-day rolling average of the daily value of trade at day t

DVT_t = daily value of trade (defined below)

The daily value of trade in a region is the sum of the products of the 48 half-hourly spot prices on that day with the 48 corresponding customer loads.

64 A simple n-period rolling average is the unweighted mean of the previous n data points. For example, a 5-period rolling average of a data point in period 10 is the simple average of the data points in day 6, 7, 8, 9 and 10.

The daily value of trade on day *t* is given by the following formula:

$$DVT_t = \sum_{i=1}^{48} P_{it} \times L_{it} \tag{3C}$$

where:

P_i = Interval *i* (half-hourly) dispatch price

L_i = Total customer load for interval *i*

Put simply, there are 365[65] RA computations in a 12-month period. The volatility factor is the maximum value of the 365 RA computations divided by the arithmetic average of these 365 RA computations.

To the extent that an increase in the MPC leads to an increase in spot price volatility, it is likely to increase the numerator of the volatility factor by more than the denominator. This is because the numerator refers to the *highest* RA over the previous 12 months whereas the denominator is an *average* of the RAs over the previous 12 months. This implies that the denominator will reflect any changes in spot price volatility in a more lagged or gradual manner than the numerator. As a result, an increase in the MPC that leads to higher spot prices will cause the volatility factor to increase. This increase could be particularly large in the short term than in the longer term when the higher spot prices caused by the higher MPC have persisted for 12 months. Any increase will, in turn, lead to an increase in market participants' prudential requirements.

4.2.2 Impact on a participant's prudential requirements

To illustrate how an increase in the MPC can lead to an increase in prudential requirements, consider the following highly stylised example. Take a hypothetical electricity retailer in New South Wales (known as 'Power Ltd') that serves a flat load of 500 MW. Assume that in the previous 12 months, the NSW spot price has been \$50/MWh all the time except for one day in which the spot price was at the MPC for six hours (and \$50/MWh for the remainder of the day). Further assume that Power Ltd has no energy, swap, cap or dollar reallocation transactions arranged in the NEM.

In this example, AEMO is required to determine the minimum Credit Support level for Power Ltd for the period beginning Jan 1st, 2010. As described above, the minimum Credit Support level is the Maximum Credit Limit.

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65 The historical observation period needs to be at least 406 days so that 365 42-day rolling averages can be computed.

Under these assumptions, the percentage changes in Power Ltd's Maximum Credit Limit due to progressively higher MPCs are as shown in Table 1.

Table 1: Percentage changes in MPC and Maximum Credit Limit

MPC ($/MWh)	% increase in the MPC	% increase in Maximum Credit Limit
$10,000	-	-
$12,500	25	13.8
$16,000	60	32.9
$20,000	100	54.4
$45,000	350	187.3
$55,000	450	234.5

Source: Frontier Economics

Note that the percentage increase in the Maximum Credit Limit is more than half of the percentage increase in the MPC. If the MPC were doubled from $10,000/MWh to $20,000/MWh, Power Ltd would require approximately 54% more Credit Support.

Table 2: Absolute changes to expected future average pool price, volatility factor and Maximum Credit Limit

MPC ($/MWh)	Average NSW spot price ($/MWh)	Volatility Factor	Maximum Credit Limit[66]
$10,000	45.55	1.922	$50,972,703
$12,500	46.99	2.120	$58,007,090
$16,000	48.93	2.379	$67,766,180
$20,000	51.01	2.651	$78,707,609
$45,000	63.99	3.931	$146,424,175
$55,000	68.08	4.303	$170,513,767

66 $\text{MCL for retailers} = \text{Daily Energy Load} \times \text{Average Pool Price (based on midpoint prices)} \times \text{volatility factor} \times \text{Loss Factor} \times$. Note that the loss factor is fixed at 1.05, (1+GST) = 1.10 and the credit time period is 42 days

Source: Frontier Economics

These percentage changes in Maximum Credit Limits can be used to derive absolute dollar amounts of required credit support by making assumptions about changes in spot prices in the region due to an increase in the MPC. In Table 2 we have assumed that average NSW spot prices will ultimately reflect the percentage changes in the estimated midpoint prices derived in section 2.3.3. This allows for the calculation of the absolute Maximum Credit Limit amounts. To reiterate the caveats made in section 2.3.3, the average spot prices are not intended to be forecasts or projections and were only provided to give an indication of the potential effects of raising the MPC.

An additional factor to consider is that as noted in the ACCC's 2000 VoLL determination, under last resort supply provisions, a defaulting retailer's customers are transferred to the host retailer. This could further enlarge an incumbent retailer's prudential obligations and market risk.[67]

Nevertheless, based on the results in section 2.3.3, a higher MPC would increase Power Ltd's volatility factor. If the MPC rises to $12,500/MWh and the average spot price rises to $46.99, Power Ltd's volatility factor would be 2.12 and the corresponding minimum level of Credit Support would be approximately $58 million. Should the MPC be increased to $16,000/MWh, the new average spot price would be $48.93. The volatility factor would be higher at 2.38 and the level of Credit Support would be $67.8 million. Much larger increases in Credit Support would be required under higher MPCs, based on the various assumptions made above.

4.3 Potential responses to increased prudential requirements

As pointed out in section 4.2, higher MPCs are likely to result in tougher prudential requirements. Potential new retail market entrants would need to secure a greater amount of Credit Support from credit support providers. It may prove to be very difficult for potential entrants to get the larger level of Credit Support required, given their lack of financial performance history or experience in the NEM.

One option for promoting or preserving competitive forces in the NEM in light of a significant increase in Credit Support requirements could be to specifically relax prudential requirements for new participants. For example, AEMO could provide a 'discount' on the minimum Credit Support level (perhaps 80% of the Maximum Credit Limit in the first financial year of operation and then 90 % for the next financial year etc). However, this would leave AEMO in a more

67 ACCC, *VoLL, Capacity Mechanisms and Price Floor, Determination*, 20 December 2000, p.23.

financially vulnerable position. Furthermore, incumbents may justifiably claim that this practice was discriminatory.

There appears to be no simple means of simultaneously preserving the financial integrity of NEM settlements and ensuring new retail entrants do not face additional barriers to entry. Given the paramount importance of preserving financial confidence in the market arrangements, it is likely that ease of new entry would need to be compromised to some extent.

Key observations

The prudential requirements in the Rules are intended to cover AEMO's worst case exposure to potentially defaulting market participants. The derivation of the reasonable worst case scenario takes account of historical spot price volatility in the NEM. To the extent that an increase in the MPC leads to an increase in wholesale spot prices, this is likely to increase this worst case exposure, and thereby increase participants' prudential obligations. Other things being equal, this could raise barriers to entry, particularly for new retailers.

There appears to be no simple means of overcoming the greater barriers to entry from a higher MPC without compromising the financial integrity of NEM settlements.

5 Risk management implications

In this section we consider the implications of an increased MPC on the management of financial risk in the NEM.

5.1 Role of contracting in the NEM

5.1.1 Need for derivative hedging

As the NEM is a compulsory energy-only electricity market, most (non-vertically integrated) market participants would be substantially exposed to spot market prices in the absence of physical or financial hedging instruments. These exposures arise because standalone:

- Generators produce electricity for which they are paid the applicable (loss-adjusted) regional reference node (RRN) price. In this sense, generators are naturally 'long' electricity because they gain if the spot price rises.
- Retailers and large customers consume electricity for which they must pay the (loss-adjusted) RRN price. Further, retailers typically supply electricity to consumers at prices that are fixed or at least do not vary according to the spot price. In this sense, retailers and large customers are naturally 'short' electricity because they gain if the spot price falls.

These long and short exposures can be managed by:

- vertical integration, which represents a form of physical hedging of spot price risk. In recent years, many market participants have become vertically integrated to some extent
- financial derivative contracts to hedge any remaining exposure to spot price risk. These instruments are described in the next section.

A market participant that is short electricity (eg a standalone retailer) will typically seek to *purchase* forward contracts and caps to reduce their exposure to high spot prices. Conversely, a participant that is long electricity (eg a standalone generator) will typically seek to *sell* forward contracts and caps to reduce their exposure to low spot prices.

The CPT also plays a role in limiting market participants' exposures to extreme continuous spot price outcomes. The rationale for the CPT and the implications of raising the CPT are discussed in section 5.2.3 below. Under extreme conditions, the Rules (clause 3.14) allow for suspension of the spot market and application of administered pricing.

5.1.2 Types and volumes of hedging instruments

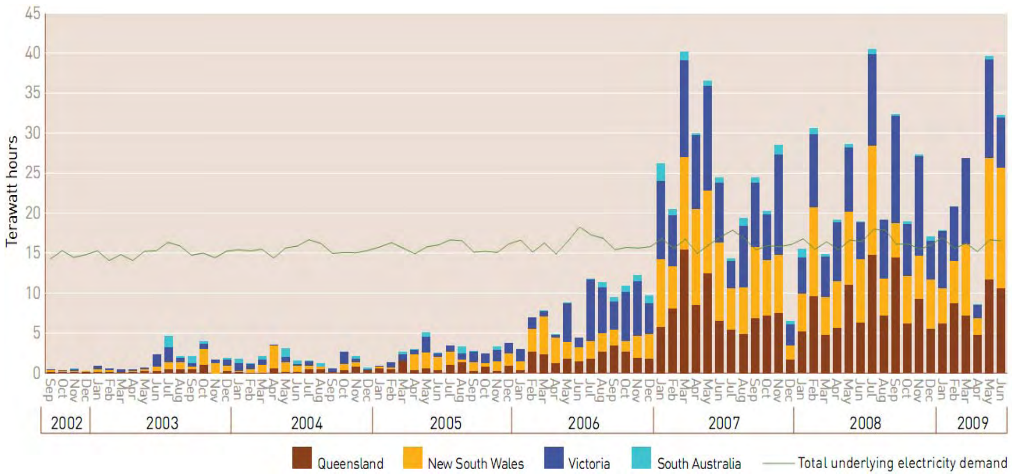
A variety of derivative contracts are available in the NEM, both as over-the-counter (OTC) instruments entered into between participant counterparties as well as exchange-traded instruments traded on the Sydney Futures Exchange (SFE). The AER's 2009 State of the Energy Market report describes the common varieties of electricity derivatives in the NEM as follows.

Box 1: Common electricity derivatives in over-the-counter and SFE markets

INSTRUMENT	DESCRIPTION
Forward contracts	An agreement to exchange the NEM spot price in the future for an agreed fixed price. Forwards are called swaps in the OTC markets and futures on the SFE.
> Swaps (OTC market)	OTC swap settlements are typically paid or received weekly in arrears (after the spot price is known) based on the difference between the spot price and the previously agreed fixed price.
> Futures (SFE)	SFE electricity futures and options settlements are paid or received daily based on mark-to-market valuations. SFE futures are finally cash settled against the average spot price of the relevant quarter.
Options	A right—without obligation—to enter into a transaction at an agreed price in the future (exercisable option) or a right to receive cash flow differences between an agreed price and a floating price (cash settled option).
> Cap	A contract through which the buyer earns payments when the pool price exceeds an agreed price. Caps are typically purchased by retailers to place a ceiling on their effective pool purchase price in the future.
> Floor	A contract through which the buyer earns payments when the pool price is less than an agreed price. Floors are typically purchased by generators to ensure a minimum effective pool sale price in the future.
> Swaptions or futures options	An option to enter a swap or futures contract at an agreed price and time in the future.
> Asian options	An option through which the payoff is linked to the average value of an underlying benchmark (usually the NEM spot price) during a defined period.
> Profiled volume options for sculpted loads	A volumetric option that gives the holder the right to purchase a flexible volume in the future at a fixed price.

Source: AER, State of the Energy Market 2009, Table 3.1, p.94.

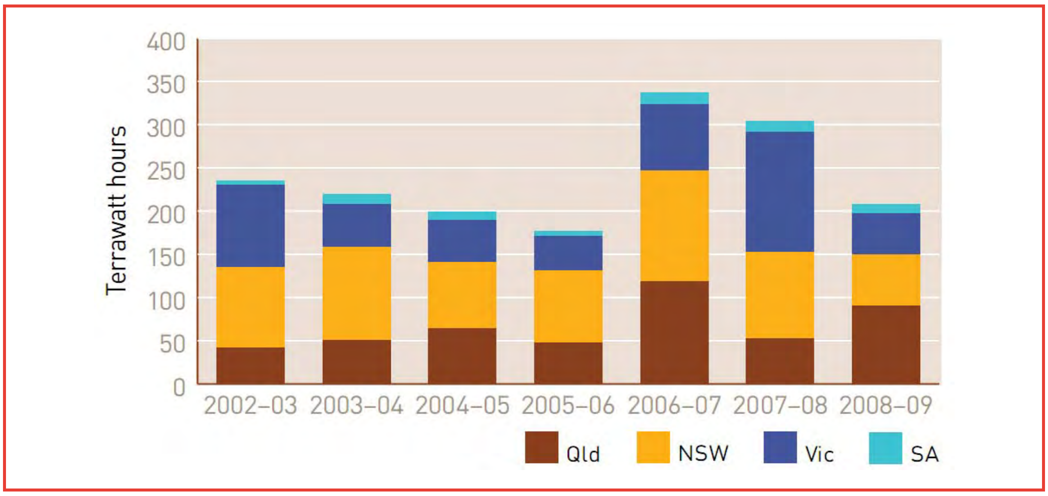
Figure 13: Regional trading volume of electricity derivatives on the SFE



Source: AER, State of the Energy Market 2009, p.97.

In recent years, the volume of SFE-traded derivatives has increased substantially, as shown.[68] Less is known about the liquidity of OTC contracts. However, the results of the Australian Financial Markets Survey (AFMA) are shown below.[69]

Figure 14: Regional trading volume of over-the-counter derivatives



Source: AER, State of the Energy Market 2009, p.99.

The majority of OTC contracts in the NEM are swaps, but caps also form a significant share of OTC derivatives. Collars, Asian options and swaptions are also used.

5.1.3 Degree of hedging and hedging considerations

Market participants, and particularly their financiers, may insist on a particular level of derivative hedging to provide a degree of certainty over future cashflows.

However, participants may wish not to be completely (100%) hedged against spot price movements. Two key reasons why participants may wish to be less than completely hedged are:

- uncertainty over future long/short position
- size of contract premiums.

Uncertainty over future long/short position

Participants may choose to retain a degree of exposure to spot prices because the extent to which they will remain short or long electricity in the future is uncertain. For example, a retailer who considers it likely (but not certain) that one of its major customers will close down may choose not to fully hedge the

68 AER, *State of the Energy Market 2009*, Figure 3.5, p.98.

69 AER, *State of the Energy Market 2009*, Figure 3.8, p.99.

business-as-usual load of that customer. This is because if the customer closes down and stops taking supply, the retailer would be long electricity at a time when spot prices may be relatively low. The costs of this risk would be exacerbated by the customer's departure from the market reducing electricity demand and prices. In these circumstances, the retailer would be effectively and involuntarily long electricity. Instead, the retailer may choose to hedge something less than the business-as-usual load of the customer to reduce the chance it may be either short or long electricity by the entire amount of the load.

A generator may choose not to fully hedge its expected output due to the risk that one or more of its units may not be fully dispatched and earn the RRP. There are two key reasons – which are largely outside the generator's control – why a generating unit may not be fully dispatched:

- one or more units may experience a forced outage, leaving the generator in a short position at a time when spot prices are likely to be relatively high (due to the outage itself)
- one or more units may be 'constrained-off', meaning that they are not dispatched even though the generator's loss-adjusted offer price is below the RRP – this occurs due to the binding of network constraints.

A generator that finds itself in a short position could be required to make 'unfunded difference payments'[70] on the volume of any forward or cap hedges in excess of its (reduced) physical output. This would harm its profitability and in extreme circumstances – namely, long periods of high prices while the generator is not dispatched – jeopardise its financial viability.

Generators adopt various strategies to manage their risks of unfunded difference payments. These include:

- Self-insurance – leaving the capacity of one or more units uncontracted – based on the idea that a generator's unit outages are usually not correlated. This is the most common way for generators to manage the hedging risk implications of forced outages.
- Co-insurance – entering into binding agreements with other generators to transfer hedging commitments if one or more generators experience a forced outage. Co-insurance arrangements would generally require approval from the competition regulator (the ACCC).

[70] 'Unfunded difference payments' refer to the obligation on a generator who has sold a swap to pay the difference between the spot price and the swap strike price. If the generator is dispatched, it would expect to earn the spot price and is so able to self-fund the difference payments on any swaps it has entered. However, to the extent that the generator is not dispatched and so does not earn the spot price on the relevant swap quantity, it has to fund the required difference payments from other sources.

- Non-firm contracts – entering into hedging derivatives that are conditional on the operational performance of the generator's plant.

We understand that self-insurance is the most common strategy used by generators to manage their risks of unfunded difference payments.

Size of contract premiums

Although participants may have strong preferences or face strong imperatives to limit their spot price exposure to a particular level, on the margin, they will have incentives to alter their degree of hedging if there are significant divergences between forecast spot prices and future spot prices implied by derivatives – known as contract premiums. In other words, spot exposure and hedging 'coverage' are to some extent substitutes and the willingness of participants to substitute between them will depend on the sign and size of the premium attaching to derivatives. For example, if a generator expects that the average spot price in the next calendar year will be $50/MWh and the strike price of the equivalent period swap contract is $52/MWh, the generator may choose to adopt a slightly lower level of swap hedging than it would if the swap strike price were $55/MWh.

In principle, swap contract premiums – defined as the difference between the swap strike price and the expected average future spot price – can be either positive or negative. Indeed, the true swap premium cannot be observed because expected future spot prices are not independently observable. The sign and magnitude of swap contract premiums will depend on a range of factors including:

- the degree of each counterparty's risk aversion
- the expected distribution of future spot prices.

If one party to a forward contract is risk-averse and the other is risk-neutral, the contract premium will favour the party who is risk-neutral (ie the risk-averse party will pay the premium to the risk-neutral party). This is consistent with the notion of forward contracts as providing insurance, with the party that values certainty paying something for that security. If both parties are similarly risk-averse, the sign and size of the contract premium will reflect other factors.

One important such factor is the expected distribution of spot prices. If this distribution is skewed towards extreme prices (say, towards the MPC), this suggests that there is greater scope for future spot prices to be *substantially higher* than the forecast average than to be *substantially lower* than the forecast average.

For example, if the expected average spot price is $50/MWh, but 99% of the time the price was expected to be $40/MWh and 1% of the time it was expected to be $1,040/MWh, there is no chance of the actual price falling more than 20% below the average while there is a small chance of the actual price rising much more than 20% above the average. The party willing to pay more to hedge this asymmetric price risk will be the party that pays the contract premium.

In practice, most swap contracts trade at a positive premium to prevailing spot prices: the AER notes that over the last four years, base futures prices traded through the SFE have tended to reflect a fairly constant premium over NEM spot prices of roughly $2/MWh.[71]

5.2 Impact of an increase in the MPC

As discussed in section 2.3, an increase in the MPC would be expected to lead to an increase in the average spot price as well as the variance or volatility of the spot price, at least in the short term.

Other things being equal, an increase in the forecast **level** and **volatility** of spot electricity prices due to a higher MPC would both tend to increase the prices of financial hedges. This would take the form of higher:

- forward contract (swap or futures) strike prices
- option strike prices and/or call option premiums.[72]

As indicated above, both the level and volatility of expected spot prices exert an important influence on future hedge prices. The extent to which the CPT may ameliorate these impacts is discussed further in section 5.2.3 below.

An increase in the MPC may also affect the liquidity and duration of financial hedges, although the direction of any changes is more ambiguous.

5.2.1 Impact on prices of financial hedges

Impact of increased level of forecast spot prices

An increase in the expected future level of spot prices should, other things being equal, lead to an increase in hedge prices. For example, if every trading interval price was expected to rise by $X/MWh, the expected average spot price would also rise by $X/MWh. This, in turn, should lead to hedge prices rising by a similar amount. For example, swap strike prices should increase by $X/MWh.

However, assuming no increase in future price volatility, contract premiums should not increase. The increase in hedging prices would only reflect the expected across-the-board increase in spot prices. Under these conditions and assumptions, the strike price of swaps contracts could potentially rise by a *similar* percentage to the average spot price increases indicated in section 2.3.3 above.

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71 AER, *State of the Energy Market 2009*, p.103.

72 Put options premiums could be expected to fall if future spot prices were expected to be higher.

Impact of increased volatility of forecast spot prices

An increase in expected spot price volatility should, other things being equal, lead to an increase in hedge prices even if there is no expected increase in average spot prices. In this case, the increase in hedge prices would be driven by an increase in contract premiums.

Contract premiums would rise because an increase in price volatility would increase the risk of extreme divergences of spot price from its average levels. For a given level of risk aversion, retailers would be willing to pay a larger premium to insure against the risk of a larger price divergence.

For example, if spot price volatility were expected to rise, then <u>at the margin</u>:

- participants who are short electricity (eg retailers) will seek to *increase* their demand for hedges to manage the risk of being exposed to extreme spot prices
- participants who are long electricity (eg generators) will tend to reduce their supply of hedges as the potential financial consequences of unit unavailability become more acute. This may be compounded by generators' incentives to keep capacity uncontracted to allow them to exercise transient market power (see below).

Under these conditions and assumptions, the strike price of swaps contracts could potentially rise by *a greater* percentage than the average spot price increases indicated in section 2.3.3 above.

2002 VoLL increase

In its 2000 VoLL determination, the ACCC took a similar view about the impact of increasing VoLL. The ACCC suggested that an increase in VoLL would increase demand for hedging instruments while reducing their supply.[73] KPMG also took this view in its report to the Council of Australian Governments (CoAG) in 2002.[74]

Therefore, both demand and supply forces in the contract market would work to increase hedging premiums over spot prices. The precise magnitude of this increase in premiums is difficult to predict without engaging in a portfolio risk modelling exercise.

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73 ACCC, *VoLL, Capacity Mechanisms and Price Floor, Determination*, 20 December 2000, p.43.

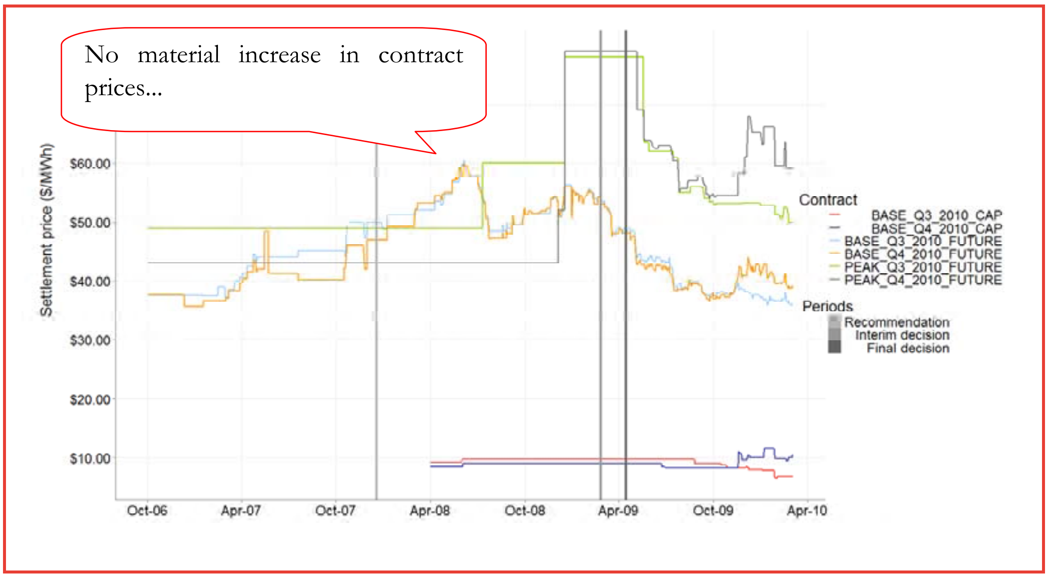
74 KPMG, *Development of Energy Related Financial Markets, Report to the Council of Australian Governments, Energy Market Review Secretariat, Final Report,* September 2002 (COAG report), p.30.

Another case worth exploring is the AEMC's recent decision to raise the MPC from $10,000/MWh to $12,500/MWh. The market had three potential dates to discover that the MPC was likely to increase from 1 July 2010:

- 21 December 2007 – the release of the Reliability Panel's Final report in which it recommended a MPC increase
- 26 February 2009 – the release of the AEMC's interim decision on increasing the MPC
- 15 April 2009 – the release of the AEMC's final decision on increasing the MPC.

To investigate whether the market perceived that an increase in the MPC would materially increase wholesale prices, we have analysed the daily closing price of various futures and caps for Q3 (Jul-Sep) and Q4 (Oct-Dec) of 2010 as offered by d-cyphaTrade and traded through the ASX. Figure 15 presents data for NSW. Figure 32 to Figure 34 of Appendix A present analogous data for Queensland, South Australia and Victoria.[75]

Figure 15: NSW contract prices



Source: Frontier Economics (d-cyphaTrade data)

Figure 15 and Figure 32 to Figure 34 indicate no material increase in the price of exchange-traded futures or caps on the dates when information regarding the increase to the MPC was released. This implies one or more of the following:

75 Exchange-traded products for Tasmania are not offered by d-cyphaTrade.

- the market did not expect that an increase in the MPC from $10,000/MWh to $12,500/MWh would materially increase wholesale spot prices
- the market learnt (or strongly expected) that the MPC was to likely to increase some time prior to the dates considered – therefore, on the dates considered, the market's expectation of future spot price increases was already reflected in contract prices
- Any potential increase in contract prices due to the MPC increasing was swamped by other factors affecting contract prices at the time – for example expectations regarding the direction of climate change policy and economic and load growth.

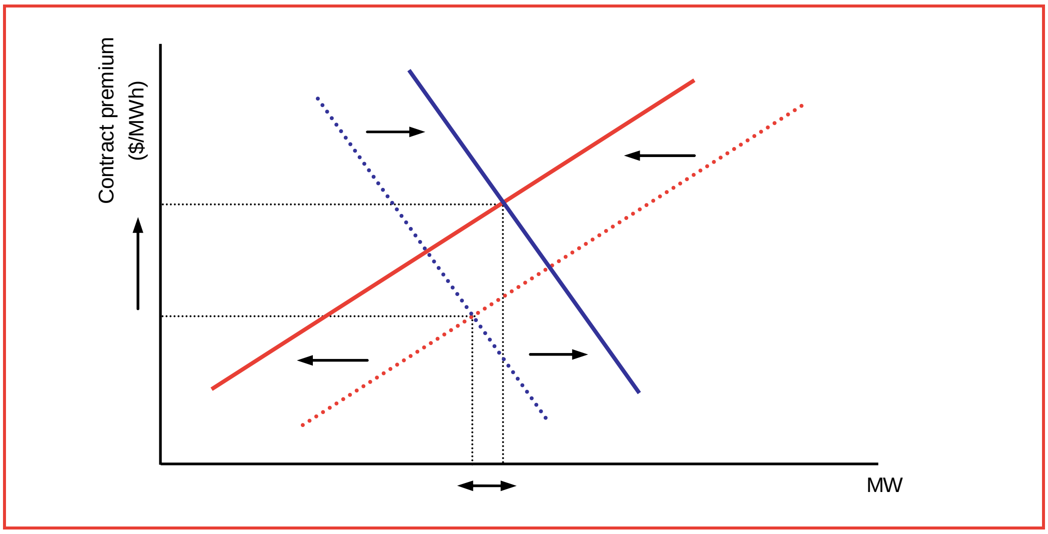
5.2.2 Contract market liquidity

Theoretical inferences

While an increase in contract premiums and risks may be an inevitable consequence of a higher MPC and CPT, the impact of a higher MPC on the volume of contracts traded – ie liquidity – is less clear. As noted above, retailers will tend to increase their demand for hedging instruments while generators will tend to reduce their willingness to supply them. The implications for the volume of hedging are ambiguous. However, to the extent that retailers are more risk averse than generators, hedging volumes may rise.

This effect can be stylistically represented as shown in Figure 16 below.

Figure 16: Impact of increased MPC on stylised contract market



Source: Frontier Economics

Previous commentary

Prior to and following the increase of VoLL in 2002, various parties commented on the contract market liquidity implications.

In July 1999, the former NECA Reliability Panel noted that improved risk management instruments were required "to allow mature, robust and diversified coverage of risk by generators and retailers".[76] The Panel also referred to the findings of a report by consultants W M Mercer,[77] who commented that it would take two to three years to develop reliable risk management arrangements.[78]

In its 2000 Determination, the ACCC highlighted the risks that contract liquidity could fall following an increase in VoLL:

> Consequently, the Commission considers that while there will be an increase in demand for risk management products, there may not be an increase in supply and it is quite possible there will be a decrease in supply.
>
> The Commission further notes the observation of several retailers that contended that they have already seen a drying up on liquidity in the market as a consequence, they argue, of a possible move to a VoLL of $20,000/MWh.
>
> The Commission also notes the conclusions of the WM Mercer report into insurance and risk management instruments for high price events. For instance, the report concluded that inter industry risk management arrangements are likely to become more difficult in the future as the need for available counterparties to cover all load [including load then hedged through vesting contracts] increases. This situation would be exacerbated by an increase in VoLL.[79]

The ACCC went on to note the then-lack of development of hedging options as well as the barriers to the development of those options and observed that:

> To increase the level of VoLL to $20,000/MWh on assumption that such [risk management] techniques will develop in the future may expose market participants to an unmanageable level of risk.[80]

Concerns about the potential lack of availability of risk management instruments was a key factor in the ACCC's decision to limit the increase in VoLL to $10,000/MWh and to defer the increase from September 2001 to April 2002.[81]

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76 NECA Reliability Panel, *Review of VoLL in the national Electricity market, Report and recommendations, Final Report*, July 1999, p.17.

77 W. M. Mercer, *Insurance and Risk Management Instruments for High Price Events*, May 1999 (Mercer report).

78 Mercer report, p.29.

79 ACCC, *VoLL, Capacity Mechanisms and Price Floor, Determination*, 20 December 2000, p.43.

80 ACCC, *VoLL, Capacity Mechanisms and Price Floor, Determination*, 20 December 2000, pp.43-44.

Following that increase, in its report to the CoAG for the Energy Market Review in November 2002, KPMG argued that an increase in VoLL would give incentives to:

- generators to reduce hedging and increasing spot market exposure
- retailers to increase hedging to minimise their spot price exposure.

KPMG suggested that:

> The combined effect of diverging responses of participants to the financial consequences of uncovered load reduces depth in the market as natural sellers of hedge cover decline to contract or increase offer prices leading to a widening of bid-offer spreads.[82]

In a December 2003 report for the NECA Reliability Panel, Tavis Consulting commented that:

> Anecdotal evidence suggests that over-the-counter and exchange based contracting steadily increased during 2002, with a significant increase in the first six months of 2003. These increases are from a small base, but nonetheless represent an improvement in liquidity. We are aware that retailers have generally increased their contracting levels and thereby reduced the exposure they have to pool price volatility. At least in part, this can be attributable to the increase in the NEM price cap to $10,000/MWh.[83]

As evident from the data on hedging volumes (see section 5.1.2 above), contract market liquidity has increased considerably since the 2002-2003 period. OTC volumes appear relatively stable, while the volume of exchange-traded hedging instruments has grown substantially. These data suggest that concerns about the maturity of the market that held the ACCC back from authorising an increase in VoLL to $20,000/MWh in 2002 ought to be lower now than they were then.

It is not possible to predict with certainty the impact of a higher MPC on contract liquidity. While concerns have been raised in the past when VoLL has been increased, we consider that the additional maturity of the derivative market means there is unlikely to be a severe adverse impact on contract liquidity. This is especially so in the longer term, as a higher MPC encourages more or earlier investment in new capacity and/or demand-side response, both of which could help ameliorate increases in hedging premiums or reductions in contract liquidity. Indeed, as shown in Figure 16, if retailers are sufficiently risk averse, liquidity may increase.

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81 ACCC, *VoLL, Capacity Mechanisms and Price Floor, Determination*, 20 December 2000, p.50.

82 CoAG report, p.30.

83 Tavis report, p.23.

Contract duration

There may also be changes in the typical duration of contracts. In its final report to the CoAG, KPMG argued that retailers would potentially seek longer term instruments.[84]

However, as with contract volumes, there are two countervailing forces at work: to the extent a higher MPC encourages retailers to seek longer term hedges, generators are conversely likely to seek shorter term hedges. In the absence of a complex modelling exercise, it is difficult to predict whether contract duration will increase, decrease or stay approximately the same.

5.2.3 Role of the CPT

CPT sets a threshold for the cumulative value of transactions over a 7-day rolling period (ie 336 half-hourly trading intervals) beyond which the Administered Price Cap applies.[85] The NECA Reliability Panel noted that the CPT was intended to operate in a similar manner to the previous force majeure provisions, which it replaced.[86] Nevertheless, the Panel noted differences between the force majeure arrangements and the CPT.[87] The force majeure threshold applied over a maximum of 3 days compared to a rolling 7 days for the CPT. Unlike the force majeure arrangements, the CPT does not require any involuntary load shedding or network outages to have occurred. This implied that the CPT is a more focussed mechanism for financial risk management than the former force majeure provisions.

The Panel noted that the presence of the CPT would allow VoLL to be increased to promote the objective of voluntary market clearing, while at the same time mitigating financial risks due to high prices. The Panel recommended setting the CPT at $300,000. This was equivalent to the force majeure threshold level of $2,100/MWh average price over 72 hours or 144 half-hours. Such a CPT level would allow a marginal supply side investment with a capital cost of $400/kW to earn up to three times its annual capital requirement of $50,000/MW/year before the administered price was applied.[88] In sum, the Panel's July 1999 comments suggest that the proposed level of the CPT was based on two considerations – risk management and reliability.

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84 CoAG report, p.31.

85 See clause 3.14 of the Rules.

86 NECA Reliability Panel, *Review of VoLL in the national electricity market, Report and recommendations, Final Report*, July 1999, p.19.

87 *Ibid.*, pp.19-20.

88 *Ibid.*, p.20.

The ACCC rejected NECA's proposal to increase the CPT in line with the proposed increase in VoLL.[89] The ACCC referred to work by its consultants, IES, which indicated that a CPT of $300,000 would be ineffective in capping risk in 'normal' market conditions and that the CPT would only be activated in catastrophic situations.[90]

The 2003 Tavis report discussed participant proposals to extend the period over which the CPT applied from 7 days to a quarter, this being a typical trading period. Tavis suggested that such a change would be undesirable, on the grounds that the CPT is only designed for situations when the market cannot provide risk management mechanisms.[91]

Given the intended role of the CPT as a substitute for the previous force majeure provisions, the growth in the volume and variety of hedging instruments since 2003 and the rise in nominal prices since 2000, we do not consider that a rise in the CPT from $150,000 to $240,000 would undermine the ability of participants to manage their residual financial risks in the NEM.

Key observations

A higher MPC could reasonably be expected to increase the prices of financial risk management instruments. An increase in hedge prices could be the result of increases in spot prices and/or the impact of greater spot price volatility on hedging premiums. Generators benefit from the higher premiums on these options. This is consistent with the rationale to increase MPC, which is to stimulate investment in new capacity.

In the absence of a dedicated modelling exercise, it is difficult to estimate how much hedge prices could rise at different levels of the MPC. However, we note that swap premiums in the NEM have consistently been about $2/MWh over spot prices.

The implications of higher MPCs on hedge market liquidity and duration are less clear. However, we see no reason to expect a large drop-off in liquidity given the near-secular increase in SFE-traded NEM hedging instruments over the past 4-5 years. We expect the now relatively mature market for hedging instruments will be able to quickly respond to changes in market participants' hedging needs due to an increased MPC. In our view, this suggests no need for policy interventions in hedging markets due to an increase in MPC and CPT.

89 ACCC, *VoLL, Capacity Mechanisms and Price Floor, Determination*, 20 December 2000, pp.44-45.

90 IES, *Modelling the Impact of VoLL and CPT in the National Electricity Market, A Report to the ACCC*, 27 October 2000, p.vii.

91 Tavis report, pp.41-42.

6 Market power

A key consideration in deciding whether to raise the MPC is whether, and the extent to which, such a change would increase the potential and incentives for participants to exercise transient market power. In this section we consider the meaning of market power, and whether increasing the MPC will affect the incentives to exercise transient market power in the NEM.

6.1 Meaning of market power

The history of concerns about market power in the NEM goes back to the initial authorisation of the National Electricity Code in 1997. In its Final Determination on raising VoLL in late 2000, the ACCC referred to concerns it raised in 1997 about the market power of generators in the NEM.[92] However, the focus of these concerns was on the structural concentration of generation portfolios, particularly in New South Wales and South Australia. At that time, the ACCC emphasised (further) structural disaggregation of generation portfolios as the key to addressing the market power issues it foresaw and was less inclined to target specific features of market design such as the MPC.

Before considering the impact of the MPC on market power, it is important to clarify what is meant by market power.

6.1.1 Trade Practices Act definition

Market power can be understood in different ways in the context of an electricity market. From an Australian trade practices law perspective, market power has been interpreted as "the ability of a firm to increase prices above supply cost without rivals taking away customers in due time."[93] Another interpretation is "the capacity to act unconstrained by the conduct of competitors".[94] In the AGL case,[95] Justice French (as he then was) found that while Loy Yang Power had enjoyed some success at 'gaming' the market during limited periods of high

92 ACCC, *VoLL, Capacity Mechanisms and Price Floor, Determination*, 20 December 2000, p.47.

93 See *Queensland Wire Industries Pty Ltd v Broken Hill Pty Co Ltd* (1989) 107 CLR 177 at p.189 (per Mason CJ and Wilson J).

94 *Boral Besser Masonry Ltd v Australian Competition and Consumer Commission* (2003) 195 ALR 609 at p.635 (per Gleeson CJ and Callinan J) and p.664 (per McHugh J).

95 Australian Gas Light Company v Australian Competition and Consumer Commission (No.3) [2003] FCA 1525

demand, this did not reflect market power even though it may have resulted in a higher forward contract price.[96]

Justice French said:

> I am prepared to accept that there are periods of high demand where a generator may opportunistically bid to increase the spot price. I do not accept that such inter-temporal market power reflects more than an intermittent phenomenon nor does it reflect a longrun phenomenon having regard to the possibilities of new entry through additional generation capacity and the upgrade of interconnections between regions. It does not amount to an ongoing ability to price without constraint from competition.[97]

Based on this reasoning, it is unlikely that the present behaviour of participants in the NEM could be characterised as reflecting the exercise of market power within the meaning of Part IV of the *Trade Practices Act* (TPA). To the extent that participants do presently exercise market power, it would be described as 'transient market power' and hence not a legitimate concern under Part IV. The approach taken in the AGL case also suggests that virtually any change in the MPC would, by itself, be unlikely to lead to such changes in the behaviour of market participants that could be described as exercising market power under Part IV.

6.1.2 Electricity market economists' definition

Energy economists (and economists generally) have taken a stricter approach to defining market power than Australian courts.

Mas-Collel et al describes market power as "the ability to alter profitably prices away from competitive levels".[98]

Stoft says market power is the ability, no matter how fleeting or minimal, to profit by moving the market price away from the competitive level.[99] He says that "market power is usually exercised by asking a higher price than marginal cost or by withholding output that could be produced profitably at the market price". Stoft goes on to say that generators in a power market can exercise market power by:

- financially withholding – raising the price of any output above marginal costs
- physically withholding – reducing output offered to the market.[100]

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96 Para 492, pp.188-9.

97 Para 493, p.189.

98 Mas-Collel, A., A. Whinston and J. Green (1995), *Microeconomic Theory*, New York, Oxford University Press, p.383.

99 Stoft, S., *Power System Economics, Designing Markets for Electricity*, IEEE Press 2002, p.317.

100 Stoft, S., *Power System Economics, Designing Markets for Electricity*, IEEE Press 2002, p.322.

Stoft says that in most cases, these are equivalent strategies. The only difference is that financial withholding strategies allow the generator greater control of prices (in that the generator can set the market price anywhere up to the level of the next highest bid or offer); but this can be no more profitable than a quantity withholding strategy (in which the generator can force the price up to the level of the next highest bid or offer). In this report, both types of strategies are referred to as 'economic withholding'.

Stoft makes clear that economists do not view the exercise of market power in a pejorative manner with necessary punitive implications.[101] He says that economists simply see the exercise of market power as a rational form of market behaviour that usually leads to inefficient outcomes. The value of the strict economists' definition, he says, is to enable such behaviour to be analysed scientifically in a non-subjective manner. This avoids the need to make legal-type distinctions between acceptable and unacceptable degrees of market power.

Economists also assume that participants behave rationally. Because market power is profitable when exercised, economists assume that rational participants will exercise all available market power. The only reason rational participants would not exercise all their market power is if they are concerned about sparking longer-term regulatory intervention.[102]

To avoid confusion, for the purposes of this report, the type of withholding behaviour that sometimes occurs in the NEM and could be influenced by a change in the MPC will be referred to as 'transient market power'.

6.2 Implications of the exercise of transient market power

As noted above, courts have not recognised transient market power as creating broader competition concerns from a public policy perspective. However, the frequent exercise of transient market power can have detrimental effects on economy efficiency in the short and long run.

In the short run, transient market power can lead to productive efficiency being compromised. Transient market power will often lead to the system operator dispatching generators with relatively high SRMC in place of generators with lower SRMC who have engaged in economic withholding strategies. This is particularly the case in the NEM, where economic withholding tends to be undertaken by incumbent generator portfolios with large amounts of baseload capacity (see 6.4 below). The dispatch of high SRMC plant in place of low SRMC

101 Stoft, S., *Power System Economics, Designing Markets for Electricity*, IEEE Press 2002, p.318.

102 Stoft, S., *Power System Economics, Designing Markets for Electricity*, IEEE Press 2002, p.318.

plant harms productive efficiency as electricity is supplied at a higher resource cost than would otherwise be the case.

In the long term, to the extent that transient market power causes wholesale prices to be higher than otherwise, it may encourage inefficiently premature generation investment. Investors may choose to invest on the basis of price signals distorted by the exercise of transient market power. This cost of this premature investment is derived from the financing cost of bringing forward investment in advance of when it is justified by fundamental (ie competitive) demand and supply forces as well as the displacement of potentially more efficient solutions.

6.3 MPC and withholding incentives

6.3.1 Conceptual relationship between MPC and withholding

As noted by academics such as Hogan[103] and Stoft[104], one of the major risks of raising the MPC (and VoLL-pricing generally) is the increased incentive for generators to engage in economic withholding strategies.

Stoft gives the following example:

- Consider 2 alternative price caps, one at $500/MWh and the other at $20,000/MWh.
- Assume the supplier in question has a capacity of 2,000 MW at a marginal cost of $50/MWh.
- Assume further that this supplier is fully dispatched and the market price is set by a more expensive plant at $100/MWh.
- This price yields the supplier in question a variable operating profit of $100,000/hour (being 2,000 MW x $50/MWh).
- Now assume load is 18,200 MW and available supply is 20,000 MW:
    - If the supplier in question withholds 1,900 MW (ie it only offers 100 MW), the supplier can push the price up to the market price cap (whether this is $500/MWh or $20,000/MWh).
    - If the MPC is $500, the supplier would earn a variable operating profit of $45,000/hour (being $450 x 100MW) – this is less than half what the supplier earns when it does not withhold.

103 Hogan, W.W., *On an 'Energy Only' Electricity Market Design for Resource Adequacy*, 23 September 2005, Center for Business and Government, John F. Kennedy School of Government, Harvard University, available here, pp. 24-26.

104 Stoft, S., *Power System Economics, Designing Markets for Electricity*, IEEE Press 2002, pp.162-3.

- If the MPC is $20,000, the supplier would earn a variable operating profit of $1,995,000/hour (being $19,950 x 100MW) – this is nearly 20 times what the supplier earns when it does not withhold.

- Therefore, while it is not profitable for the supplier to withhold at a MPC of $500/MWh, it is extremely profitable to withhold at a MPC of $20,000/MWh.

Stoft concludes, "VoLL pricing provides strong incentives for the exercise of market power."[105] We agree with this conclusion and base our analysis on the premise that a higher MPC creates greater incentive for generators to exercise transient market power.

6.3.2 Incentives to withhold in the NEM

Generators can exercise transient market power in the NEM by withholding or re-pricing their available capacity at particular times, requiring AEMO to accept higher-priced bids or offers to meet demand and thereby pushing up spot prices.

As in the hypothetical example above, the profitability of such behaviour increases as the MPC increases, as the potential 'payoff' from creating an artificial scarcity of supply is greater. This point was acknowledged by the Reliability Panel in its 1999 report recommending an increase in VoLL to $20,000/MWh.

> An increase in the level of the market price cap recommended in this report will have the effect of increasing the alternatives for balancing supply and demand under extreme conditions when abuse is potentially attractive. It will also reduce any perceived need or justification to act in a non-competitive manner. However it will also increase the potential return from it.[106]

This incentive was also noted in a report by Concept Economics prepared for the Reliability Panel in 2008.[107]

In its 2000 VoLL determination, the ACCC reiterated concerns it had expressed prior to market start about market power in the NEM. The ACCC commented that despite significant ongoing investment in generation and interconnection, spot prices in South Australia and Queensland suggested that market power was a problem. While accepting that a higher VoLL would increase investment in peaking capacity that may mitigate the market power of incumbent generators, the ACCC commented that at least until this new capacity was brought on line, a

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105 Stoft, S., *Power System Economics, Designing Markets for Electricity*, IEEE Press 2002, p.163.

106 NECA Reliability Panel, *Review of VoLL in the national electricity market, Report and recommendations, Final Report*, July 1999, p.13.

107 Concept Economics, *Risk Assessment of Raising VoLL and the CPT*, 13 October 2008, p.38.

higher VoLL would increase generators' incentives to withhold or withdraw capacity or otherwise bid in a manner to force up prices.[108]

6.3.3 Regulation of bidding

There is presently no outright prohibition against generators withholding capacity, or pricing opportunistically or in manner that does not reflect their costs in the Rules or elsewhere in the NEM architecture.

The principal constraint against opportunistic bidding and rebidding is the 'good faith' provisions introduced in February 2003. These provisions only require that market participants' bids and offers represent their genuine intentions at the time they are made. On the eve of the introduction of these obligations, NECA, as the proponent of the changes, said:

> The changes introduce an obligation for bids and offers to reflect market participants' genuine intentions at the time they are made. This obligation will apply in both the energy and ancillary services markets. It will apply both to initial bids and any subsequent rebids. The obligation is not intended to restrict, much less prohibit, legitimate bids and rebids. We have consistently made clear our view that, subject to appropriate safeguards and adequate disclosure, the ability for participants to rebid is essential to the efficient and effective operation of the market. We have also provided analysis which demonstrate that, overall, rebidding leads to lower spot market prices than would otherwise have been the case. ***Nor do we intend to seek to enforce the 'good faith' obligation in a way that would prevent participants acting and reacting commercially, including in the light of changes to material contract as well as physical market conditions***.[109] (emphasis added)

The experience of the application of these provisions is discussed in the next section in the context of the evidence of transient market power in the NEM.

6.4 Evidence of transient market power in the NEM

We consider below the history of transient market power in the NEM, before considering how a higher MPC might affect it in future.

6.4.1 AER and NECA incident reports

Under the NER, the AER has responsibility for monitoring compliance with the Rules and publishing reports on market performance. Under clause 3.13.7(d) of the Rules, the AER is required to publish a report whenever the spot price exceeds $5,000/MWh. This report must describe the factors that contributed to the price exceeding $5,000/MWh including the withdrawal of generation capacity and network availability.

108 ACCC, *VoLL, Capacity Mechanisms and Price Floor, Determination*, 20 December 2000, pp.47-48.

109 NECA, *Changes to bidding and rebidding rules*, January 2003, p.1.

Since it was formed in July 2005, the AER has published 47 reports assessing the incidents of prices exceeding $5,000/MWh in at least one NEM region for at least one trading interval.[110] Many of the reports assess incidents that occurred over multiple days and multiple regions. Our analysis of these reports indicates that the typical scenario leading to high spot prices involves either demand being higher than forecast or a plant or network outage that results in higher-priced plant being dispatched. In some – but not all – cases, generators rebid a proportion of their capacity into higher price bands in response to the changed demand and/or supply conditions. As noted above, such behaviour is not proscribed under the Rules.

Table 3 Factors present when spot prices exceeded $5,000/MWh

Number of reports	Demand exceeded forecast	Pant derating, network outages or transmission constraints	Generators exercising transient market power
47	41	37	29

Source: AER "Prices above $5000/MWh" reports from 31st October 2005 to 18th January 2010, available from the AER website here.

Table 3 describes the number of instances in which a certain factor was used to explain the high spot prices. In the 47 reports produced by the AER, demand for energy exceeded the forecasts in 41 of them. There were 37 instances of plant derating, network outages and transmission constraints. Based on Frontier's interpretation of the AER reports, generators exercised market power by rebidding capacity at higher price bands on 29 occasions.

The AER also publishes incident-specific reports on its investigations into participants' compliance with the Rules. Seven such reports have been prepared since the AER commenced. A number of the AER's investigations concerned potentially unlawful bidding or rebidding by participants. However, most of these could not be described as generators seeking to exercise transient market power. In particular, generators sometimes bid or rebid their plant as 'inflexible'[111] or reduce their plant's ramp rates[112] to increase (rather than decrease) their dispatch at times of high prices. This behaviour cannot properly be described as exercising market power because there is no withholding of capacity (physical or financial) and the profitability of such behaviour does not rely on changing the spot price. The only report dealing with an alleged breach of the good faith bidding

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110 See the AER website here, accessed on 9 March 2010.

111 See the AER website here on its *Investigation into the events of 22 March 2006* and the AER's penalty notice here.

112 See AER, *Investigation Report, The events of 31 October 2005, Final*, October 2006, p.9, available here.

provisions found that the information available did not support a breach of the Rules by participant in question (AGL Energy Limited).[113]

Prior to the formation of the AER, NECA had published a number of investigation reports since market start. A number of the NECA reports referred to generators repricing their capacity into higher price bands following a system event of some kind or a change in demand or supply conditions. However, no breaches of the good faith bidding provisions were identified.

When VoLL increased from $5,000/MWh to $10,000/MWh in April 2002, the frequency of generators exercising transient market power actually fell. In its report reviewing the performance of the NEM over the summer of 2002-03, NECA commented that:

> Rebidding activity reduced by a quarter compared to last summer, in part reflecting the generally milder weather. The biggest reductions occurred in New South Wales and South Australia. Shifting of capacity between price bands contributed to two-thirds of all rebids.[114]

6.4.2 AER State of Market Reports

The AER has to date published State of the Market reports for 2007, 2008 and 2009. These reports cover a range of electricity (as well as gas) topics, including generation developments, wholesale NEM outcomes, energy financial markets outcomes, transmission and distribution network regulation and retail market competition.

Each report comments in general terms on the circumstances and causes of extreme price events over the relevant year. The 2008 and 2009 reports went into more detail, singling out the bidding strategies of AGL Electricity in South Australia (where it owns the Torrens Island power station (TIPS)) as being responsible for a number of extreme price spikes.[115] The AER referred to several cases where AGL Energy bid large proportions of TIPS capacity at or near $10,000/MWh at times of extremely hot weather and record demand.

The 2008 report noted that the AER was investigating whether generator bidding behaviour breached the National Electricity Law and Rules.[116] The 2009 report referred to the AER's findings that AGL Energy's bidding was not in breach of

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113 AER, *Investigation Report, AGL's compliance with the good faith rebidding provision of the National Electricity Rules on 19 February 2008*, May 2009, p.6, available here.

114 NECA, *Assessment of the market's performance during summer 2002-03*, March 2003, p.2, available on the AER's website here.

115 AER, *State of the Energy Market 2008*, pp.87-88; AER, *State of the Energy Market 2009*, pp.81-87. TIPS accounts for approximately 40% of South Australia's generation capacity.

116 AER, *State of the Energy Market 2008*, p.88.

the Rules.[117] The 2009 report also provided brief details of all price spikes above $5,000/MWh over the 2008-09 financial year, briefly summarising the information contained in the AER's Rule-mandated reports.[118]

6.4.3 energy C21 speech

More detailed comments on various instances of generators exercising transient market power were made by ACCC Commissioner and AER Member, Ed Willet, in a speech to a conference in Melbourne on 8 September 2009.[119] Mr Willet referred to examples of 'opportunistic bidding' by:

- Macquarie Generation in June 2007
- AGL in the first quarter of calendar 2008 and 2009
- Hydro Tasmania since 1 June 2009.[120]

Mr Willet noted that offering generation capacity at above-competitive prices is not a breach of the Rules and nor are the rebidding rules aimed at regulating the 'misuse of market power'.[121] He also questioned the suitability of applying the provisions in the TPA to such behaviour.[122]

6.5 Impact of an increase in the MPC and CPT

In our view, it is likely that an increase in the MPC and CPT will increase the incentives for, and incidence of, generators exercising transient market power in the NEM to some degree. This will, other things being equal, tend to increase wholesale spot (and ultimately derivative) prices. Moreover, the increase in transient market power – and impact on wholesale prices – is likely to be greater the higher the level to which the MPC is raised. However, as noted in section 6.4.1 above, the level of the wholesale price will also depend on factors other than the increase in the MPC – for example, demand, weather and plant and network outages. In some cases, as in the summer of 2002-03, changes in these other factors may outweigh the impact of a higher MPC.

In the shorter term, the level of generator hedging in the NEM will exert a strong influence on generators' incentives to exercise transient market power. As noted in section 5.2.2 above, it is difficult to predict whether the overall level of

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117 AER, *State of the Energy Market 2009*, p.86.

118 AER, *State of the Energy Market 2009*, p.87.

119 Willet, E., *State of the energy market*, energy 21C, 8 September 2009, Melbourne, available here.

120 Willet, E., *State of the energy market*, energy 21C, 8 September 2009, Melbourne, pp.3-4.

121 Willet, E., *State of the energy market*, energy 21C, 8 September 2009, Melbourne, p.5.

122 Willet, E., *State of the energy market*, energy 21C, 8 September 2009, Melbourne, p.6.

hedging will increase or decrease in response to a higher MPC. If hedging increases, this will tend to mitigate generators' incentives to engage in withholding strategies, because they will have less to gain (at least in the short term) from pushing up spot prices by reducing their dispatched output. On the other hand, if the net level of hedging stays about the same or falls, generators will have similar or stronger incentives to engage in withholding strategies.

In the longer term, to the extent that a higher MPC (and CPT) leads to higher wholesale prices, this should encourage more investment in generation capacity, which could help reduce the ability and incentives of generators to exercise transient market power. However, due to the lumpiness of investment and relatively lengthy build times, this period may be quite painful for consumers. Further, it is possible that additional investment in capacity may come from existing suppliers, which would consolidate rather than diffuse generation market structure. The larger a single generator's portfolio relative to the size of the market, the more likely it will have and exercise transient market power. This is because, other things being equal, a generator with a relatively large portfolio has both:

- the ability to withhold a greater amount of capacity and hence a greater likelihood of being able to influence the spot price
- more to gain from an increase in the spot price caused by a given MW withheld

than a generator with a relatively small portfolio.

The first point follows directly from the greater capacity of a larger generator. A generating portfolio of 1000 MW can withhold a larger amount of capacity than a generating portfolio of 400 MW. Further, the withholding of, say, 500 MW is more likely to lead to an increase in the spot price than the withholding of 200 MW (representing half the capacity of each portfolio, respectively).

The second point follows from the fact that a given amount of MW withheld represents a smaller share of a large generating portfolio's capacity than it does of a small generating portfolio's capacity. This means that the large generator is likely to have a larger quantity of dispatched generation on which it can earn a boosted price than the small generator.

For example, assume that in market with 1000 MW capacity and 900-950 MW peak demand, the withholding of 50 MW of capacity at peak times has a 20% chance of pushing the spot price to the MPC and an 80% chance of having only a minimal impact on the spot price. Under these conditions, and assuming zero contracting, the risk of implementing a 50 MW withholding strategy would be:

- more attractive to a 400 MW generator – who would gain the MPC on seven-eighths (350 MW/400 MW) of its capacity if the strategy were successful

- than to a 100 MW generator – who would gain the MPC on only half (50 MW/ 100 MW) of its capacity if the strategy were successful.

Having said that, larger generation portfolios are better able to hedge a greater proportion of their capacity than smaller portfolios, due to the ability of larger portfolios to self-insure for outage risk. A higher level of contracting will reduce incentives to exercise transient market power, because the benefits from increasing the spot price can only arise in relation to uncontracted output. Therefore, to the extent that generation investment is undertaken by incumbents, the implications for competition may not be entirely negative.

Nevertheless, we consider that an increase in the MPC will tend, at the margin, to increase generators' incentives to exercise transient market power. However, it is difficult to project the precise extent to which this will occur in the absence of detailed dispatch modelling allowing for strategic bidding by key participants. What can be said is that higher and higher MPCs should provide progressively stronger incentives to exercise transient market power and hence, lead to progressively high wholesale prices. Therefore, a MPC of $55,000/MWh should encourage more exercise of transient market power and higher prices than a MPC of $45,000/MWh, which should in turn encourage a greater exercise of market power and higher prices than MPCs of $16,000/MWh or $12,500/MWh.

6.6 Potential responses to increased exercise of transient market power

There are limited mechanisms presently in place in the NEM to prevent or deter the exercise of transient market power. Nevertheless, if an increase in the MPC were to increase generators' incentives to exercise transient market power, a number of responses could be considered.

6.6.1 Changes to bidding rules

The Rules governing generator bidding in the NEM are targeted at ensuring bids and rebids are made with honest and genuine intent at the time they are made, rather than preventing the exercise of transient market power.

Proscribing rebidding

One option for preventing the exercise of transient market power could be to proscribe generator rebidding altogether. However, such an option would be unlikely to achieve its intended objectives. To take one example, NECA's investigation into the events of Tuesday 17 December 2002 referred to participants rebidding capacity into high price bands in response to high demand

and tightening gas supplies.[123] Interestingly, however, the spot price for one of the two relevant dispatch intervals was set by a generator (Ladbroke Grove) that had not rebid any capacity – its capacity was already priced at $8,591/MWh, which would have been well above its marginal costs of operation.[124] The report also explained that rebidding earlier in the day had helped to *reduce* forecast afternoon prices.[125]

This example illustrates why it is difficult to prevent participants from exercising transient market power through simple rules proscribing rebidding: Rebidding is neither a sufficient nor a necessary condition for the exercise of transient market power and it may in fact be pro-competitive. As noted in section 6.3.2 above, this point was acknowledged by NECA when it introduced the good faith bidding Rules in 2003.

Proscribing conduct prejudicial to the NEM

At the time it proposed the good faith bidding provisions, NECA proposed a prohibition on "bids or rebids that have the purpose, or have or are likely to have the effect, of materially prejudicing the efficient, competitive or reliable operation of the market." NECA's proposed guidelines gave examples of conduct that would breach this prohibition. Most of these examples involved what could be described as attempts to exercise transient market power.

The ACCC rejected NECA's proposals, primarily on the grounds that:

- the proposals imposed obligations on participants that were unreasonable or too uncertain or
- the benefits of the prohibitions would not clearly exceed their costs.

For example, the ACCC referred to the proposal to proscribe "economic withholding" – the placing, by a generator, of a significant amount of capacity in one or more very high price bands, thus removing that capacity from the likelihood of dispatch. This would lead to a fall in supply, and often, higher spot prices. The ACCC noted that:

> …a generator's decision to offer plant capacity in a high price band could have arisen from the asset owner's preference to not use the unit, due to maintenance requirements, or other technical limitations. Only when a sufficiently high dispatch price becomes a reality may the asset owner risk using the unit. Where the generator considers the price insufficient to cover the risk, the generator is not likely to use the

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123 NECA, *Investigation into the events of Tuesday 17 December 2002, Report*, March 2003.

124 NECA, *Investigation into the events of Tuesday 17 December 2002, Report*, March 2003, p.3.

125 NECA, *Investigation into the events of Tuesday 17 December 2002, Report*, March 2003, p.2.

> unit. This appears to be a legitimate strategy, and could actually work to the benefit of the market in contributing capacity to the reserve margin.[126]

Indeed, in our view, a key rationale for a market with bid-based dispatch is that individual generators are in the best position to determine when, how much and for what price they should supply electricity.

The ACCC expressed similar concerns about the proposed prohibitions of:

- "sleeper bids" – where capacity is placed in very high price bands from the outset and remain there
- the exploitation of network constraints, reductions in capacity or increases in demand – where a generator rebids capacity in to higher price bands when it learns of a circumstance that tightens the demand-supply balance in a region.

SRMC bidding rules

Another option is to require generators to offer their capacity at their short run marginal cost (SRMC). Such rules are currently in place in the Western Australian wholesale electricity market.[127] However, the determination of individual generator SRMCs can be complicated and thus often needs to be quite prescriptive and intrusive. For example, start-up costs need to be incorporated into SRMCs. The Western Australian Economic Regulatory Authority (ERA) has published various papers on the calculation of SRMC and continues to consult with the market on the shape and interpretation of this rule.[128]

In its 2007 Annual Report to the Minister, the ERA commented that it was "not aware of outcomes in the [Short Term Energy Market (STEM)] that indicate market power as an issue".[129] However, it considered that there was a need to investigate bidding patterns and the causes of high price outcomes. The ERA said:

> Given that generation capacity in the market remains highly concentrated at this stage, there is a concern that outcomes in the market may not reflect competitive outcomes. Patterns of STEM offers indicate that Market Participants have consistently offered significant quantities at high prices, including prices at, or close to, the energy price limits. The IMO and the Authority continue to work on assessing STEM offers and bids to identify any outcomes that indicate market power.[130]

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126 ACCC, *VoLL, Capacity Mechanisms and Price Floor, Determination*, 20 December 2000, p.28.

127 See *Wholesale Electricity Market Amending Rules* (1 March 2010), clause 6.6.3, p.287, available from the Independent Market Operator website here.

128 See the ERA website here.

129 ERA, *Annual Wholesale Electricity Market Report for the Minister for Energy, Public Version*, 21 December 2007, available here, p.vii.

130 ERA, *Annual Wholesale Electricity Market Report for the Minister for Energy, Public Version*, 21 December 2007, p.44. Note that the 'energy price limits' refer to the separate liquid and non-liquid price caps in

As far as we are aware, no major changes have been implemented in the Western Australian market to address these concerns.

In its latest 2008 Annual Report to the Minister, the ERA expressed concern that allowing multiple 'gate closure' – akin to allowing bidding or rebidding closer to real-time – could raise market power issues if dominant participants had the opportunity to rebid.[131]

Reformed United States electricity markets, such as the Pennsylvania-New Jersey-Maryland (PJM) market, do not have SRMC bidding rules in their energy, capacity and ancillary services markets as such.[132] However, PJM and other north-eastern United States markets such as New York, New England, Midwest and California all apply rules for screening and 'mitigating' (ie directly reducing) generators' offers in each of their markets under certain conditions. For example, in the PJM energy market, PJM directly caps the price of out-of-merit generators' offers to incremental cost plus 10% at those times that the generator in question is considered to have structural market power due to the presence of transmission constraints.[133] This involves the application of the 'three pivotal supplier test', which finds a generator to be 'pivotal' (and hence holding 'structural market power') if its output is required to relieve a transmission constraint into a 'load pocket'. Generators subject to offer-capping still receive the higher of the market price and their offer price. There is no capping of the offers of generators that are 'in-merit'.[134]

According to the independent organisation responsible for market monitoring in PJM, Monitoring Analytics, the levels of market power mitigation have been low and have fallen in recent years. Since 2005, the proportion of hours in which offer capping has applied in the real-time energy market has fallen from 1.8% to 0.4% in 2009. The proportion of MWs offer capped has fallen from 0.4% to 0.1% over the same period. These proportions have been even lower in the day-ahead energy market.

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place in the Western Australian market. These are presently $469/MWh for liquid fuel plant and $276/MWh for non-liquid fuel plant – see the ERA website here.

131 ERA, *Annual Wholesale Electricity Market Report for the Minister for Energy, Public Version*, 5 November 2008, available here, p.63.

132 Note that PJM and other northeast US markets operate separate markets for day-ahead and real-time energy, capacity and for ancillary services such as regulation reserve.

133 See O'Neil, R., U. Helman, B.J. Hobbs and R. Baldrick, "Independent System Operators in the USA: History, Lessons Learned and Prospects", Chapter 14 in Sioshansi, F.P. and W. Pfaffenberger (Eds), *Electricity Market Reform, An International Perspective*, Elsevier (2006), pp.479-528, p.510.

134 O'Neil, R., U. Helman, B.J. Hobbs and R. Baldrick, "Independent System Operators in the USA: History, Lessons Learned and Prospects", Chapter 14 in Sioshansi, F.P. and W. Pfaffenberger (Eds), *Electricity Market Reform, An International Perspective*, Elsevier (2006), pp.479-528, p.510.

In its regular State of the Market Reports, Monitoring Analytics has commended three pivotal supplier test, finding that:

> The result of the introduction of the three pivotal supplier test was to limit offer capping to times when the local market structure was noncompetitive and specific owners had structural market power. The analysis of the application of the three pivotal supplier test demonstrates that it is working successfully to exempt owners when the local market structure is competitive and to offer cap owners when the local market structure is noncompetitive. [135]

As a result, Monitoring Analytics recommended maintaining the existing market power mitigation rules in PJM.[136]

Other reformed United States markets have more intrusive criteria than PJM for applying market power mitigation, particularly outside of constrained load pockets. Inside constrained load pockets, generators offers tend to be capped to some measure of cost-based prices. For example, in the New England market, offers are capped at the net annual fixed cost of a generator divided by the expected number of run hours. In the Midwest market, offers are capped at the net annual fixed costs of a new peaker divided by the total constrained hours over the previous twelve months. However, the main differences with PJM lie outside of load pockets. If generators' offers exceed a market-based reference price by a particular amount and lead to a change in the market price beyond a certain amount, then offers are capped to the reference price. However, O'Neil et al observe that because generators know their reference price and the bounds established by the conduct-impact test, they rarely behave in ways that trigger offer mitigation.[137]

In addition to clarifying the nature of SRMC, the implementation of SRMC bidding caps would require a substantial monitoring effort by the AER or equivalent body. Such a body would be required to examine offers that appear to depart from the plant's SRMC and determine whether or not those offers breached the rules. As with NECA's proposed economic withholding prohibition (see above), we consider that such arrangements would defeat many of the advantages of a bid-based market. After all, if a centralised agent is capable of reliably determining SRMCs, there would seem to be little point in enabling participants to submit their own bids.

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135 Monitoring Analytics, *State of the Market Report for PJM 2009*, p.18, available here; see also Monitoring Analytics, *State of the Market Report for PJM 2008*, p.2, available here.

136 Monitoring Analytics, *State of the Market Report for PJM 2009*, p.8.

137 O'Neil, R., U. Helman, B.J. Hobbs and R. Baldrick, "Independent System Operators in the USA: History, Lessons Learned and Prospects", Chapter 14 in Sioshansi, F.P. and W. Pfaffenberger (Eds), *Electricity Market Reform, An International Perspective*, Elsevier (2006), pp.479-528, p.510.

6.6.2 Adjust MPC and/or CPT downwards

Another option that is strictly outside the scope of this report's terms of reference is to implement a lower MPC than deemed necessary to meet reliability standards and/or reduce the multiple of the MPC used to determine the CPT.

Any downward adjustment to the MPC would be based on the presumption that generators can and will exercise transient market power, and so should be able to earn sufficient intra-marginal rents from a lower MPC to recover their total costs.

If this approach were to be adopted explicitly, it would need to done very carefully to avoid compromising reliability. Many other factors would need to be considered such as:

- regulatory risk from extant and potential market reviews that seek to discourage withholding strategies and which may thereby jeopardise investment that is only made profitable on the basis that those strategies could continue
- risk of ongoing state ownership of generation assets, which may discourage generation investment[138]
- retail price caps, which discourage full exploitation of transient market power by vertically integrated suppliers.

Moreover, this approach has its own drawbacks. In particular, it would require predicting how and when transient market power would be exercised, and permanently tie together the determination of the MPC and the level of transient market power.

The rationale for raising the MPC while reducing the multiple of the MPC used to determine the CPT would be that it would allow the spot prices to rise sufficiently to promote new generation investment for reliability while mitigating generator incentives to exercise transient market power. After the CPT is reached, the spot price is set at the Administered Price Cap of $300/MWh until the CPT is no longer exceeded.[139] While this would eventually reduce economic withholding incentives under sustained supply scarcity conditions, it would have a limited effect during shorter periods of high prices. Further, not allowing the CPT to increase proportionately with the MPC may undermine the reliability rationale of raising the MPC and may require the MPC to be raised more than would otherwise be necessary.[140]

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138 See the findings of the 'Owen Inquiry' (*Inquiry into Electricity Supply in NSW*, available here), pp.7-14 to 7-16.

139 See the AEMC website.

140 See ROAM Consulting, *Reliability Standard and Settings Review*, Draft Report to the AEMC, 15 January 2010, p.22.

6.6.3 Capacity mechanisms

An alternative means of meeting reliability objectives while minimising incentives to exercise market power is to implement some form of capacity mechanism. This would enable the MPC to be set lower than it would in the absence of a capacity mechanism. For example, the northeastern US markets all have 'safety net' offer caps of $US1,000/MWh.[141] As we were asked to consider the (non-reliability) implications of a higher MPC and CPT, such options are outside the scope of this report. However, some capacity options that could be compatible with an energy-only market were discussed in the Tavis report.[142]

Key observations

A high MPC can create incentives for generators to exercise transient market power in the NEM. While this may not raise broader Trade Practices Act concerns, if it occurs frequently, transient market power can raise wholesale prices and compromise economic efficiency in both the short and long run. Increasing the MPC is likely to increase existing incentives to exercise transient market power because it increases the 'payoff' to any given generator from engaging in economic withholding strategies.

Various regulatory and market design options are available to mitigate generators' incentives to exercise transient market power. The regulatory options include measures to restrain generators' offers directly and downward adjustments to the MPC and/or CPT. The market design options include implementing some form of capacity mechanism to sit alongside the energy-only market. However, all of these options have drawbacks and create risks of their own for the maintenance of sufficient capacity to help meet the NEM reliability standard.

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141 O'Neil, R., U. Helman, B.J. Hobbs and R. Baldrick, "Independent System Operators in the USA: History, Lessons Learned and Prospects", Chapter 14 in Sioshansi, F.P. and W. Pfaffenberger (Eds), *Electricity Market Reform, An International Perspective*, Elsevier (2006), pp.479-528, p.510.

142 See section 5.

7 Inter-regional trade

In the present context, inter-regional trade encompasses:

- physical flows of electricity between NEM regions – this involves considering the effect of a higher MPC and CPT on the frequency and duration of transmission constraints
- derivative trading across NEM regional boundaries – this involves considering any impediments to inter-regional hedging caused or exacerbated by a higher MPC and CPT.

This section also discusses the extent to which the effect of raising the MPC and CPT on inter-regional trade could also influence the overall efficiency of new investment in generation and transmission capacity in the NEM.

We consider the impact of a higher MPC implemented uniformly across the market, as well as an MPC set at different levels in different regions. The current proposal is for MPC to be set uniformly across the NEM.

7.1 Market-wide increase in MPC and CPT

A change to the MPC and CPT – if done uniformly on a market-wide basis – will not directly affect inter-regional trading of electricity. However, increasing these variables could indirectly influence inter-regional trade in both the short and the long term, as discussed below.

7.1.1 Short term impacts

Network constraints

In the short term, to the extent that a higher MPC increases incentives to exercise transient market power (see section 6.3 above), this could change the pattern of transmission constraints in the NEM. It is very hard to generalise about the tendency, nature or costs of these effects. Due to a combination of network topology, demand conditions and generation costs, locations and contracting levels, a variety of potential outcomes are possible. For example:

- Generators with transient market power in regions experiencing high demand may engage in more aggressive withholding strategies than they would with a lower MPC. This could *reduce* the prevalence of transmission constraints on lines within regions close to the regional reference node (RRN).
- Generators without transient market power within these regions could have increased incentives to bid their capacity below SRMC (as low as negative

$1,000/MWh) in order to maximise their dispatch volumes and settlement returns. This could *increase* the prevalence of binding constraints in some locations.

- Generators in adjacent regions that are not experiencing as tight supply scarcity conditions may continue to bid relatively competitively. This could lead to increased constraints on interconnectors at regional boundaries.
- Generators within a region experiencing supply scarcity and located on notional interconnectors could bid below SRMC while adjacent regions' RRPs are below the RRP of the supply scarcity region. This could simultaneously lead to constraints on notional interconnectors between the RRN and remote intra-regional generators (those on the far side of constraints and unable to affect the RRP as a result) and counter-price flows from higher-priced regions to lower-priced regions. If 'clamping'[143] is applied, interconnector capacity at regional boundaries may be relatively unconstrained.

Some of these behaviours and outcomes may reflect an improvement in economic efficiency while others could reflect a deterioration. More definitive commentary would require detailed market dispatch modelling, similar to that undertaken by Frontier for the AEMC on the Snowy regional boundary change proposals.[144]

Inter-regional hedging

Section 5 above discussed the implications of raising the MPC and CPT for derivative trading generally. With a 'normal' (intra-regional) hedging instrument, the buyer and seller of the instrument are located in the same NEM region and settle derivatives against their local RRP. This gives rise to various risks including:

- counterparty risks – less an issue for exchange-traded derivatives than for OTC instruments and
- risks of being inadvertently long or short electricity – in particular, generators face the risk of making unfunded difference payments in the event of forced plant outages.

However, entering derivatives settled against the RRP of a different region to where a participant is located brings additional risks. The key risk is that the RRP at which the participant is settled for its electricity consumption or generation diverges from the RRP against which the derivative instrument is settled. This is

143 Clamping refers to the curtailment of power flows on a notional interconnector, often to avoid counter-price flows.

144 See the Appendix B to the AEMC's Final Decision on the Abolition of the Snowy Region available from the AEMC's website.

commonly referred to as 'basis risk'. To the extent that a higher MPC can increase the potential magnitude of divergence between:

- the RRP for the region where a participant is located and is settled and
- the RRP at which a derivative instrument entered into by the participant is settled,

this could increase the risks of entering such instruments.

The NEM design allows participants to acquire inter-regional settlement residue (IRSR) units through settlement residue auctions (SRAs) to hedge inter-regional basis risk.[145] However, the reliability of the hedge that these instruments provide for managing basis risk (ie their 'firmness') varies greatly and may not be sufficient to encourage participants to enter inter-regional contracts even at the present level of MPC.[146] A higher MPC is unlikely to increase the firmness of IRSR units and may decrease their firmness if power flows between regions are more likely to be limited at times of large inter-regional price divergences than at times when RRPs are more aligned.

For these reasons, increases in the MPC would be likely to further increase the risks of inter-regional contracting broadly in proportion to the change in the MPC. This is because a higher MPC would increase the severity of inter-regional price divergences and the magnitude of basis risk experienced by a participant considering entering into an inter-regional hedge. This could discourage inter-regional hedging and may ultimately contribute to inefficient longer term locational signals for new investment (see below).

7.1.2 Long term impacts

Inefficient location of investment

To the extent that a higher MPC results in less firm IRSR units and deters participants from entering inter-regional electricity derivatives, a higher MPC may distort the locational decisions of new generation investors. While, other things being equal, it is efficient for generators to locate in regions experiencing higher prices, this incentive may be inefficiently heightened if investors considering locating their plant in adjacent regions are deterred from doing so in order to avoid basis risk.

Inefficient type of investment

In the longer term, any disparity between the MPC and the value of customer reliability (VCR) used in regulated network investment assessments could create

145 See AEMC, *Congestion Management Review – Final Report*, June 2008, available here, p.27.

146 AEMC, *Congestion Management Review – Final Report*, June 2008, available here, pp.15-16.

inefficiencies to the extent that interconnection proceeds ahead of generation. The current Regulatory Test includes as one of the benefits of transmission investment, "changes in involuntary load shedding using a reasonable forecast of the value of electricity to consumers".[147] Expanding on this provision, the AER's Application Guidelines refer to "VCR or a comparable estimate of the value consumers place on electricity".[148] VCR is currently $55,000/MWh.[149]

To the extent that VCR exceeds the MPC, other things being equal, regulated network investment (or regulated alternatives to network investment) will precede market-driven investment. While a private investor may not find it profitable to develop, say, a new generator if the MPC is $12,500/MWh, a TNSP may find that a regulated network investment that performs a similar function could provide a net economic benefit and satisfy the test because unserved energy is valued at VCR ($55,000/MWh). As the Regulatory Test applies to both network and non-network alternatives, over time, the disparity could lead not only to regulated network augmentations 'crowding out' unregulated generation and demand-side response projects, but also to regulated projects *generally* crowding out market-driven projects. The prospect of such a distortion was discussed by the NECA reliability Panel in its 1999 review of VoLL.[150]

This suggests that increasing the MPC towards the VCR should promote a more efficient mix of generation and transmission investment in the NEM. In this respect, a MPC of $16,000/MWh is likely to improve investment signals compared to a MPC of $12,500/MWh, while an MPC of $55,000/MWh would eliminate the bias in favour of regulated network investments under the network regulatory arrangements.

7.2 Region-specific MPC and CPT

The AEMC's Second Interim Report on the Review of the Effectiveness of NEM Security and Reliability Arrangements in light of Extreme Weather Events raised the prospect of applying different MPCs and CPTs in different NEM regions.[151] However, the Commission noted that:

> there are a number of impacts of such an arrangement that could lead to distortions in investment and operational outcomes than that suggested from purely the

149 See AEMC Reliability Panel, *Annual Market Performance Review 2008-09, Final Report*, 18 December 2009, p.71.

150 NECA Reliability Panel, *Review of VoLL in the national electricity market, Report and recommendations, Final Report*, July 1999, p.16.

151 See AEMC website here, section 4.3, pp.41-47.

> price/reliability trade-off arising from differential MPCs which in turn could detract from achieving economically efficient outcomes across the NEM.[152]

As a result, the Second Interim Report recommended comprehensive analysis including modelling to consider a range of potential implications of applying different MPCs in different regions.

We share the AEMC's concerns and consider that applying different MPCs in different regions could bring a range of unintended and perverse outcomes, including for inter-regional trading of electricity in both the spot market and in hedging instruments.

Key observations

Raising the MPC and CPT could indirectly influence inter-regional trade in both the short and the long term.

In the short term, a higher MPC could change the pattern of transmission constraints in the NEM. However, it is very hard to generalise about the tendency, nature or costs of these effects. It is clearer that a higher MPC would be likely to further increase the basis risks of inter-regional contracting in the NEM. This could discourage inter-regional hedging and may ultimately contribute to inefficient longer term locational signals for new investment.

In the longer term, to the extent that a higher MPC results in less firm IRSR units and deters participants from entering inter-regional electricity derivatives, a higher MPC may distort the locational decisions of new generation investors. New generators may be more encouraged to locate in the same regions as their intended counterparties than is warranted on the basis of the underlying relative costs.

However, by reducing the gap between the MPC and the VCR, a higher MPC could reduce the present bias in favour of regulated investment under the existing network regulatory arrangements.

We agree with the AEMC that applying different MPCs in different regions could bring a range of unintended and perverse outcomes.

152 p.47.

8 Transitional and systemic risk issues

An increase in MPC may raise transitional and systemic risks for the market which are discussed below.

8.1 Transitional issues

The issue of transitional risks was discussed in the Reliability Panel's July 1999 report recommending an increase in VoLL.[153] The Panel paid particular attention to the following matters:

- need for improved risk management instruments
- transitional features of the NEM are inhibiting full development of the market – vesting contracts, lack of ToU metering and FRC.

The Panel's key concern was ensuring that participants exposed to a higher MPC would be able to manage that exposure through energy derivatives, which were not far advanced at that stage.

As a result, the Panel recommended a staged increase in VoLL, with:

- 25 months lead time until a change from $5,000/MWh to $10,000/MWh (from July 1999 to 1 September 2001
- a further 7 month lead time until a change from $10,000/MWh to $20,000/MWh (from 1 September 2001 to 1 April 2002).[154]

The ACCC's 2000 VoLL determination rejected an increase in VoLL to $20,000/MWh and postponed the increase to $10,000/MWh until 1 April 2002 – approximately 15 months from the date of the final determination.[155] The ACCC cited many of the same issues as the Reliability Panel (such as vesting contracts) but expressed greater concern regarding the prospects for the development of suitable risk management instruments and also emphasised the lack of demand-side participation in the market.[156] As a result of these concerns and the passage of time since the Panel recommendation, the ACCC considered that a September 2001 start-date for an increase in VoLL – leaving 10 months' lead time – was insufficient.

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153 NECA Reliability Panel, *Review of VoLL in the national electricity market, Report and recommendations, Final Report*, July 1999, pp.17-18.

154 NECA Reliability Panel, *Review of VoLL in the national electricity market, Report and recommendations, Final Report*, July 1999, p.18.

155 ACCC, *VoLL, Capacity Mechanisms and Price Floor, Determination*, 20 December 2000, pp.51-52.

156 ACCC, *VoLL, Capacity Mechanisms and Price Floor, Determination*, 20 December 2000, p.45.

Currently the MPC is already due to rise to $12,500/MWh this year and ROAM has proposed a subsequent increase to $16,000/MWh from 1 July 2012.[157]

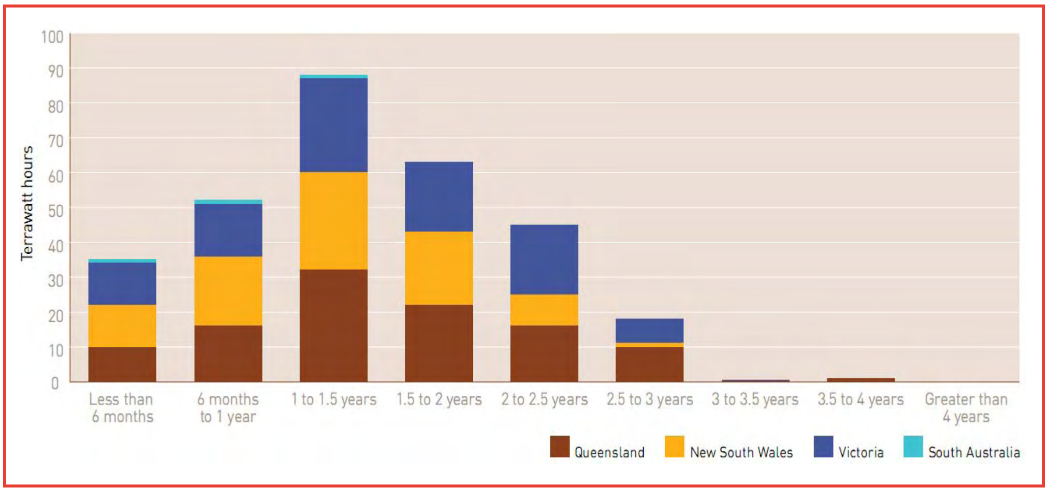
We believe these lead times are sufficient:

- in light of the greater liquidity and maturity of the exchange-traded derivative market compared to 2000 (see Figure 13 above in section 5.1.2) and
- given that more than three-quarters of exchange-traded instruments have a duration of less than 2 years (see Figure 17 below).

Another important issue is to allow sufficient time for participants to supply any additional prudential requirements that could become due in light of expected higher spot price volatility. In our view, this is also a matter of providing a reasonable lead time for any change to the MPC.

Therefore, as long as a formal decision on raising the MPC to $16,000/MWh from 1 July 2012 in made in the near future, we consider that participants should have enough time to manage transitional issues such as contractual positions and prudential requirements.

Figure 17: Traded volume of futures contracts by date-to-maturity (2008-9)



Source: AER, State of the Market 2009, p.98.

If the MPC were further increased in later years, say, to $20,000/MWh, $35,000/MWh or even up to $55,000/MWh, we consider that participants would likewise be able to manage the transitional risks if a sufficient lead time was provided. The appropriate lead time would need to be reviewed at the relevant time in light of evidence surrounding the prevailing nature and popularity of various hedging instruments and the availability of credit support.

157 ROAM Consulting, *Reliability Standard and Settings Review*, Draft Report to the AEMC, 15 January 2010, p.27.

8.2 Systemic risks

An issue that arose with the Government's proposed CPRS legislation was the systemic risk it could impose on the NEM by undermining participant asset values.

By design, any scheme intending to reduce carbon emissions will relatively disadvantage carbon-intensive generation. As has been flagged by numerous parties,[158] the imposition of a carbon price has the potential to significantly erode the value of emissions-intensive generators. It was argued that this rapid value erosion could trigger debt covenants regarding financial ratios such as gearing or operating profits. This, in turn, could allow financial counterparties to these distressed entities to terminate bilateral derivative contracts. The collapse of several such contracts could then lead to a contagion of contract defaults throughout the market.

Putting to one side the likelihood of this outcome, the above scenario is a *feasible* systemic risk associated with the introduction of an emissions trading scheme. By contrast, it is difficult to conceive how a higher MPC might pose a similar risk to the integrity of the NEM. Putting to one side any transitional impacts of increasing MPC, a higher MPC would not be expected to substantially undermine the value of either generators or retailers and large loads in the NEM. As such, it would be unlikely to pose systemic risks of a similar nature as may be posed by the CPRS.

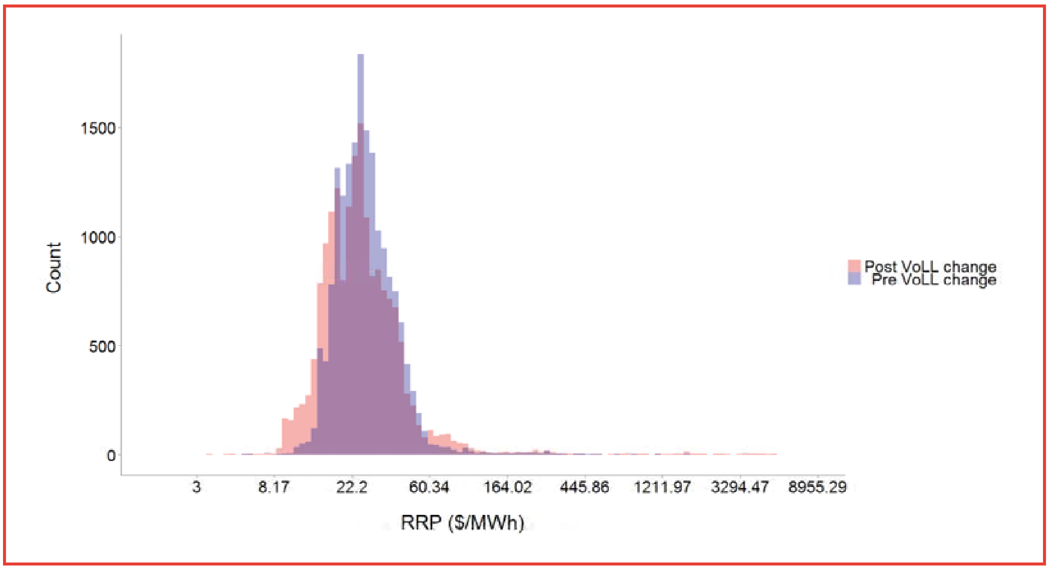
Key observations

An increase in MPC may raise transitional risks for the market. The key issue is to ensure that there is a sufficient lead time between the timing of a formal decision to raise the MPC and its implementation to allow derivative markets to reflect any expected changes to spot market outcomes and to allow participants to arrange any additional prudential support. In our view, the proposed lead time for the proposed increase in MPC to $16,000/MWh from 1 July 2012 is likely to be appropriate if a formal decision to endorse this proposal is made in the near future. We do not consider that the planned increases to the MPC and CPT give rise to any material systemic risks for the market.

158 See, for example, submissions made by the ESAA (available here) and Babcock and Brown Power (available here).

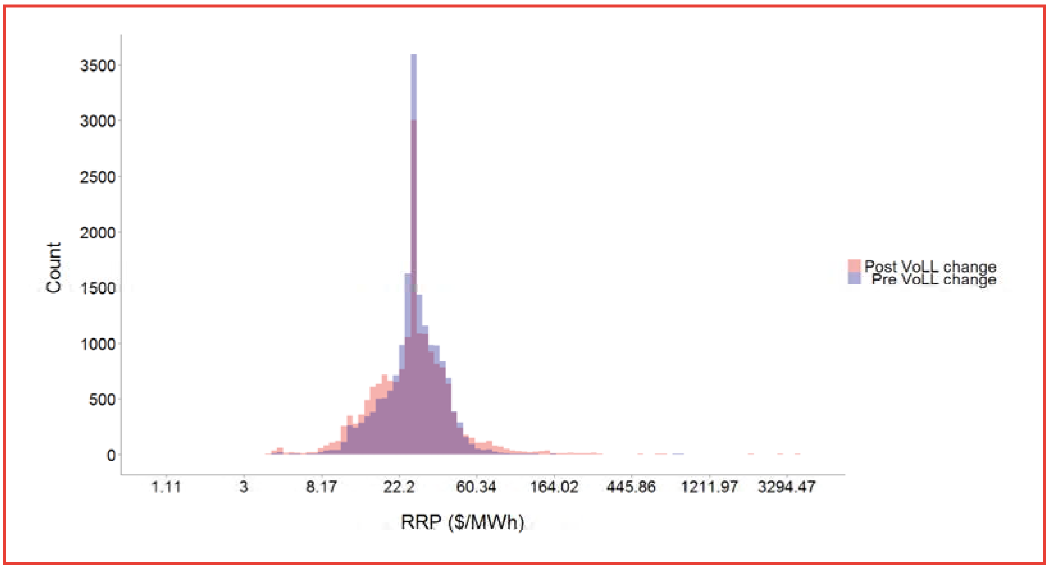
Appendix A

Figure 18: Distribution of QLD spot prices (pre- and post- VoLL change)



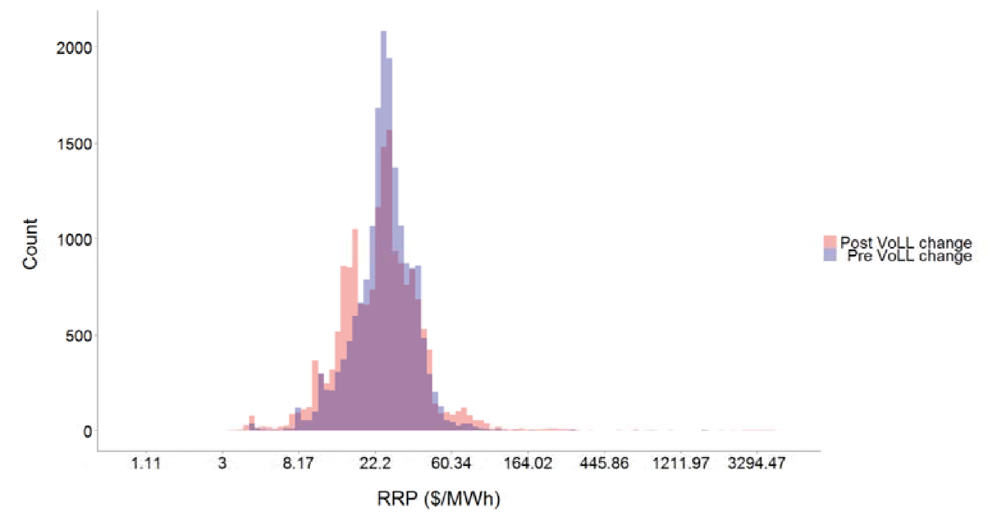
Source: Frontier Economics

Figure 19: Distribution of SA spot prices (pre- and post- VoLL change)



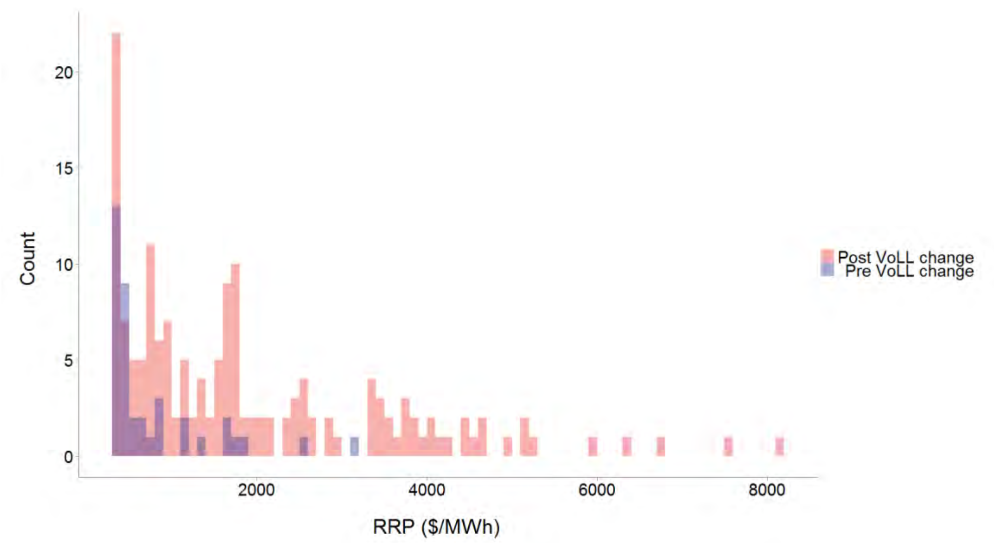
Source: Frontier Economics

Figure 20: Distribution of VIC spot prices (pre- and post- VoLL change)



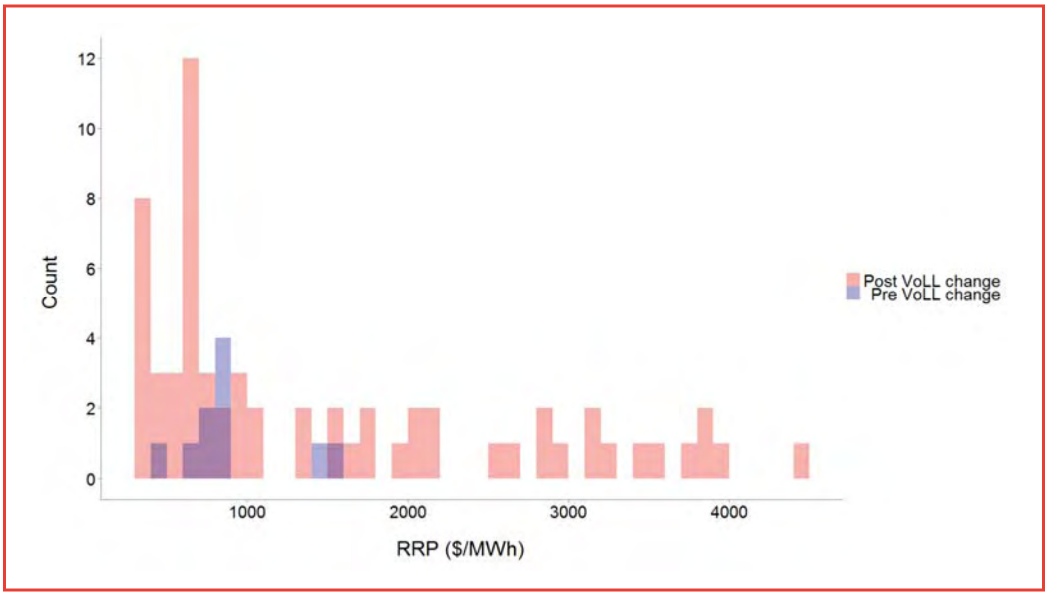
Source: Frontier Economics

Figure 21: Distribution of QLD spot prices > $300 (pre- and post- VoLL change)



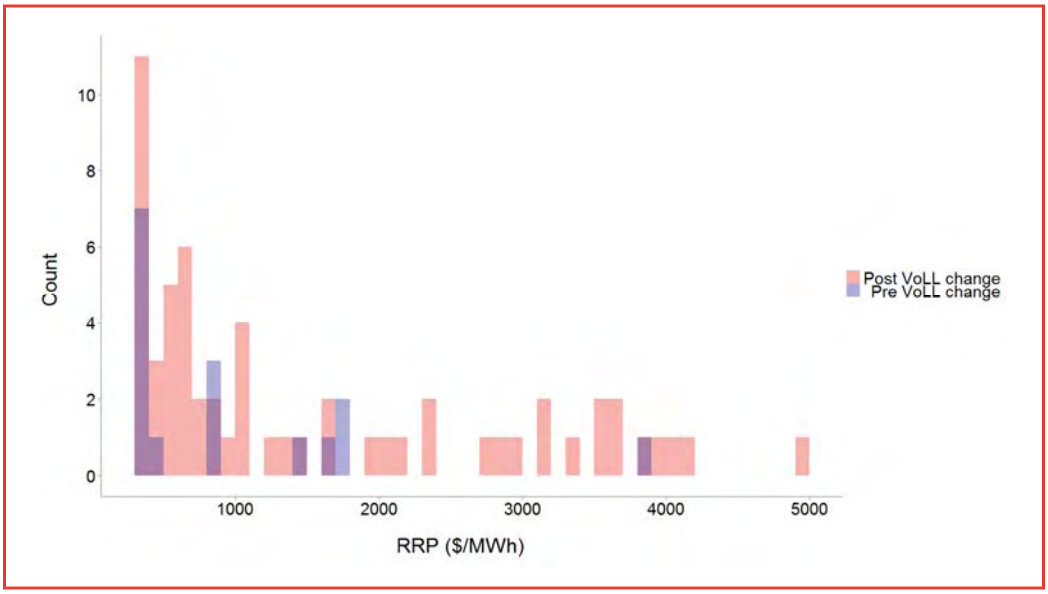
Source: Frontier Economics

Figure 22: Distribution of SA spot prices > $300 (pre- and post- VoLL change)



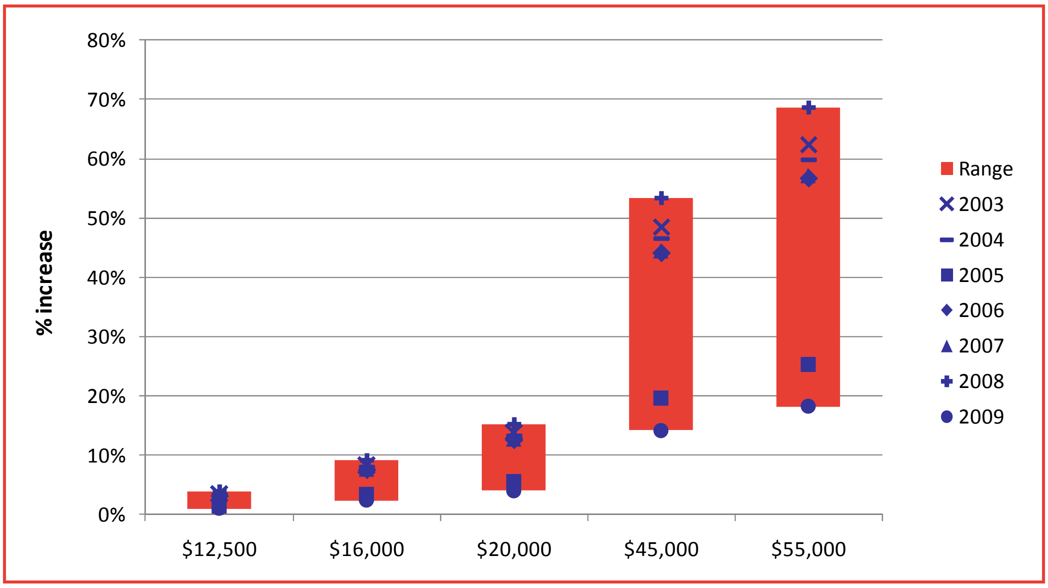
Source: Frontier Economics

Figure 23: Distribution of VIC spot prices > $300 (pre- and post- VoLL change)



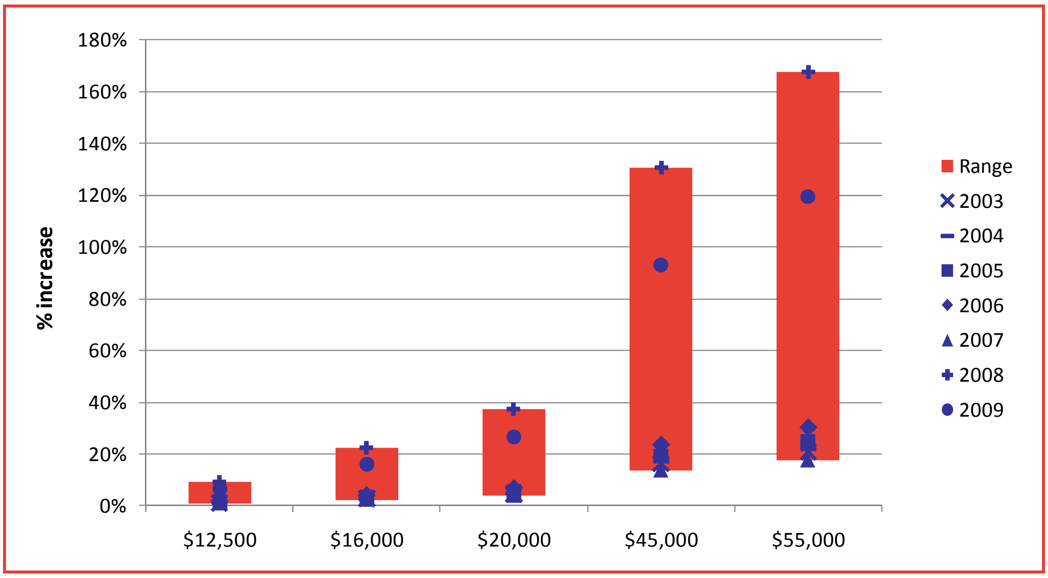
Source: Frontier Economics

Figure 24: Time-weighted average price increases (QLD)



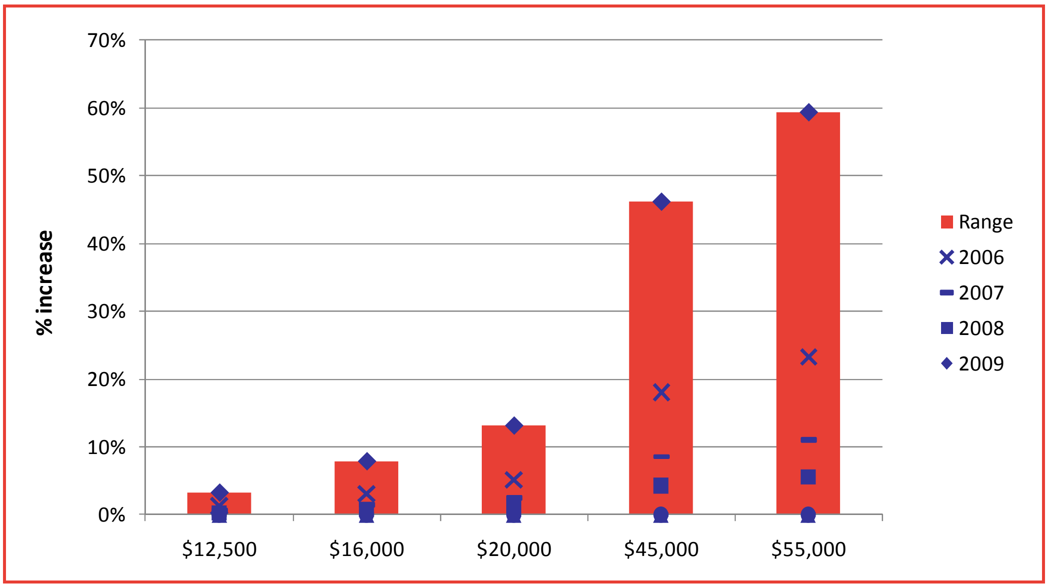
Source: Frontier Economics

Figure 25: Time-weighted average price increases (SA)



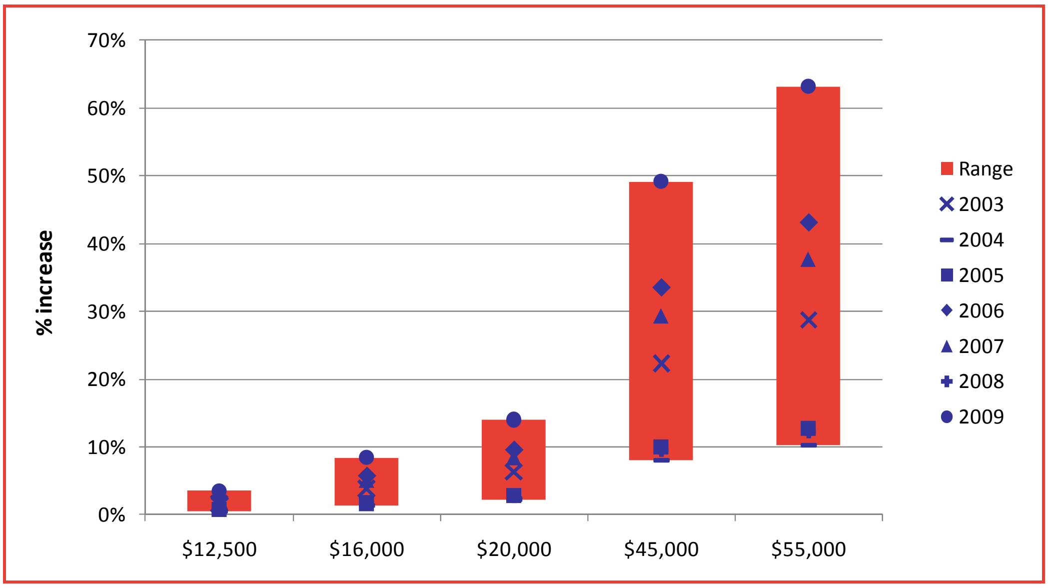
Source: Frontier Economics

Figure 26: Time-weighted average price increases (TAS)



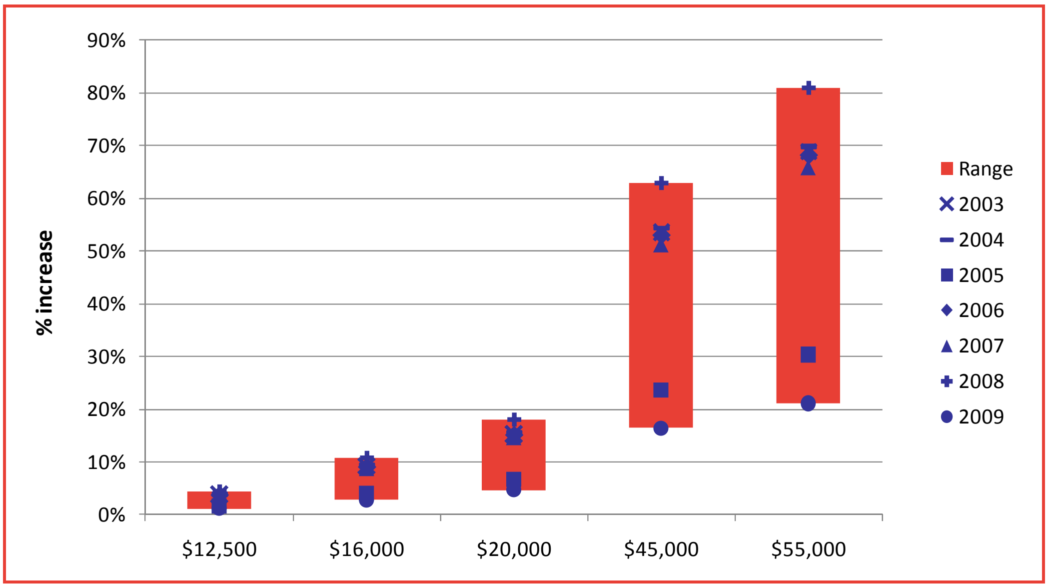
Source: Frontier Economics

Figure 27: Time-weighted average price increases (VIC)



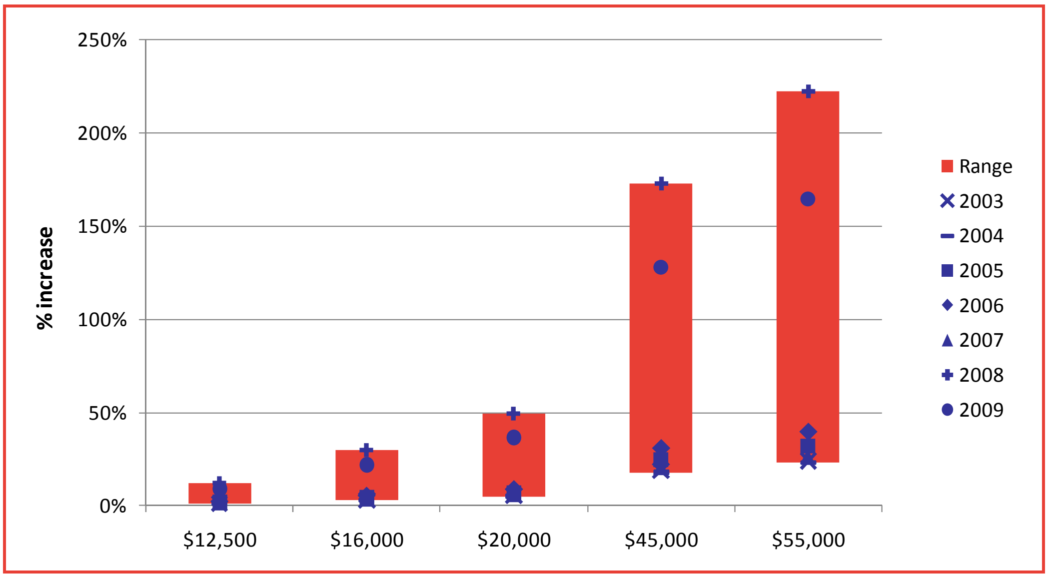
Source: Frontier Economics

Figure 28: Demand-weighted average price increases (QLD)



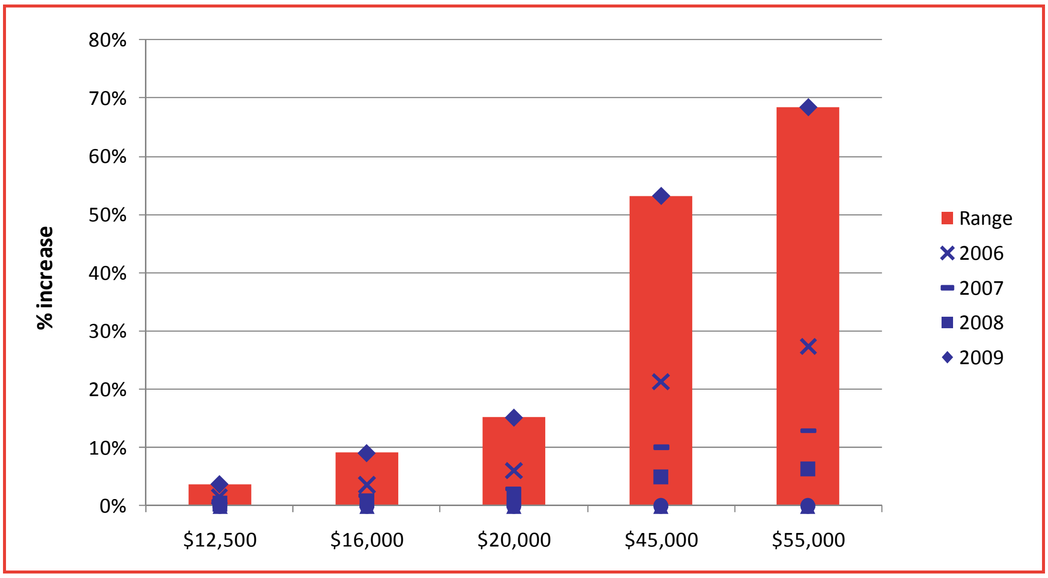
Source: Frontier Economics

Figure 29: Demand -weighted average price increases (SA)



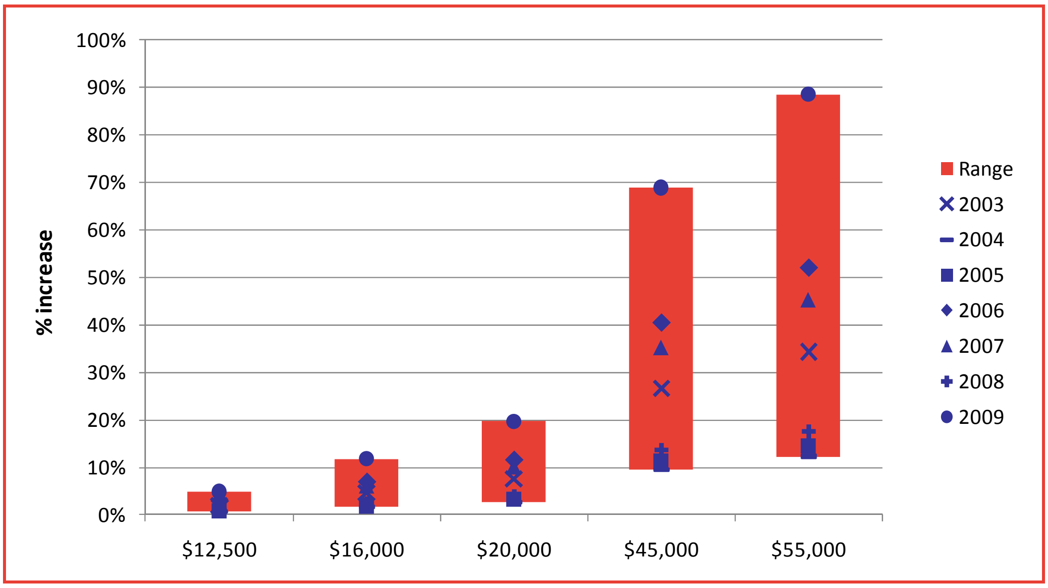
Source: Frontier Economics

Figure 30: Demand -weighted average price increases (TAS)



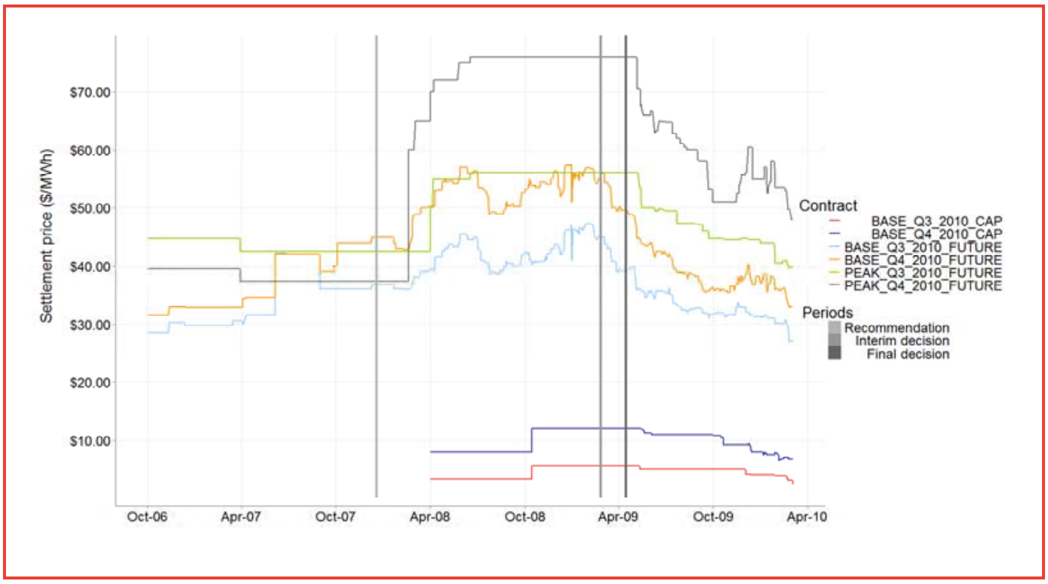
Source: Frontier Economics

Figure 31: Demand -weighted average price increases (VIC)



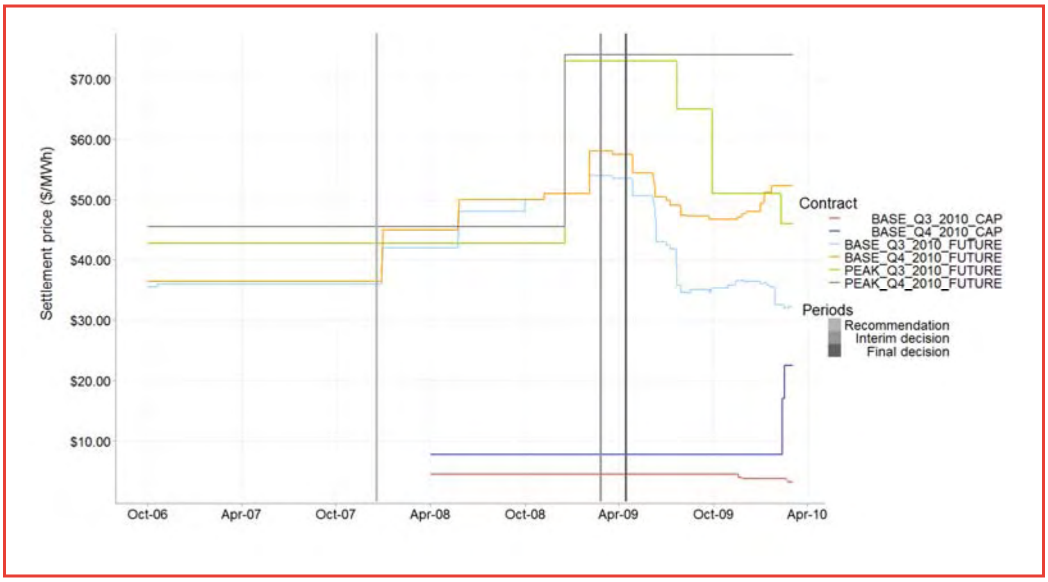
Source: Frontier Economics

Figure 32: QLD contract prices



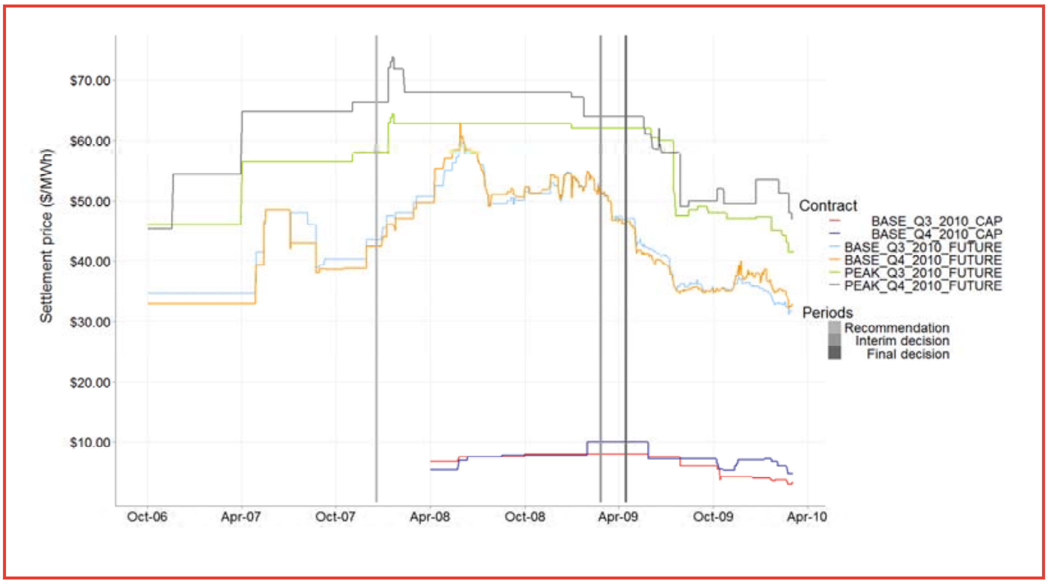
Source: Frontier Economics

Figure 33: SA contract prices



Source: Frontier Economics

Figure 34: VIC contract prices



Source: Frontier Economics

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