concept economics

REPORT

RISK ASSESSMENT OF RAISING VOLL AND THE CPT

Prepared for:
The Reliability Panel

Prepared by:
Deb Chattopadhyay

Date: 13 October 2008
Project code: 0084.0185

Concept Economics:
27 Jardine Street,
PO Box 5430 Kingston
ACT 2604 Australia

For further information on this report, please contact the project manager of this report on +61 3 9583 2888 or email debchattopadhyay@concepteconomics.com.au.

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EXECUTIVE SUMMARY

The Reliability Panel of the Australian Energy Market Commission (AEMC) has engaged Concept Economics ('Concept') to provide advice concerning the impact of proposed increases in the value of lost load ("VoLL") and the cumulative price threshold ("CPT") on (quoted text from the terms of reference is shown in ***bold italics***):

- ***"financial risks faced by participants in the National Electricity Market ("NEM");***
- ***the level of systemic, market-wide risks; and***
- ***the efficiency and efficacy of the packages of VoLL, CPT, Administered Price Cap ("APC") and compensation arrangements ("Compensation") and their settings in mitigating systemic, market-wide risk <u>at times of extreme financial stress</u>."***

This report examines each of the issues raised in the AEMC's terms of reference, aside from alternative compensation arrangements. Alternative compensation arrangements, including proposals regarding compensation put forward by EA, are examined in detail in a separate Concept study.[1]

COMMERCIAL CONTEXT

Volatility of spot prices in the NEM is an intrinsic part of an "energy only" market design. All generators and especially peaking generators rely on price volatility to recover fixed investments. The package of VoLL, CPT, APC and Compensation mechanisms provides a "safety valve" to limit the risk exposure for all market participants against **extreme** price volatility. These mechanisms may be summarised as follows:

1. VoLL is a cap on spot prices currently set at $10,000/MWh that limits the exposure to prices in a single period;
2. If half-hourly spot prices in a region on a rolling 7-day basis exceed the CPT, an APP is declared, and prices in the region are capped to the APC currently set at $300/MWh for all periods;[2] and
3. Dispatch and associated uncapped spot prices during an APP are calculated per the normal procedure and these are used to compensate eligible market participants.[3]

[1] Concept Economic, *Risk Assessment of Alternative Compensation* Options, Draft Report Submitted to the AEMC, July, 2008. Of course, as is apparent from the discussion in this report, there is a close interrelationship between compensation and other aspects of risk management. Hence, it is necessary in parts to discuss issues relating to compensation. That said, an analysis of the merits and drawbacks of alternative compensation arrangements is beyond the scope of this particular report.

[2] Prices in other regions exporting to the region may be scaled to prevent power flows on interconnectors occurring from low price regions to high price regions, i.e., avoid any instance of negative inter-regional settlement residues as per Rule 3.14.2(e).

[3] As defined by Rule 3.14.6.

The setting of VoLL-CPT-APC together with a compensation mechanism is intended to strike a balance between:

1. Containing extreme price risk for those who buy energy while,
2. At the same time, providing liberal allowances to ensure that investment in peaking generation is not disadvantaged.

Achieving this balance is paramount. As electricity market failures elsewhere have shown, persistently volatile prices can cause extreme financial hardship to retailers and extreme measures to curb such volatility (e.g., setting a very low price cap) have dried up investment in generation. Although these impacts may be localised in some cases, restricted to one region or even an individual participant, there are often flow-on effects, such that a series of localised financial failures can lead to a systemic market-wide risk.

The Reliability Panel's terms of reference emphasise the following three key issues that define the scope of this study:

- Financial risks should be considered broadly, and include both:
  - Physical sources of risk (e.g. outages on generation, transmission and fuel supply system); and
  - Risks associated with the increased ability or incentives for generators to alter their bidding behaviour, and the effect this may have on prices;
- An assessment of financial risks needs to consider risks faced by all market participants, including:
  - Investment and revenue risks for generators and other parties, such as network service providers (NSPs); and
  - Cost risks faced by retailers;
- The efficacy of the total package of risk mitigation measures, i.e., VoLL-CPT-APC-Compensation, is an important consideration. Increases in VoLL and/or CPT need to be assessed carefully to see if they strike a reasonable balance for both purchasers and sellers of energy. Similarly, compensation to generators based on an administered price should consider the impacts on all market participants, including retailers and generators, to ensure a balanced outcome. Alternative compensation schemes (e.g. direct cost, opportunity cost, bid/offer based compensation) may affect market participants differently.

There are three proposed changes to the settings of VoLL, CPT and APC that have been discussed recently:

- The Comprehensive Reliability Review that concluded in December 2007, which recommended increasing VoLL to $12,500/MWh from the current level of $10,000/MWh and the CPT to $187,500 from the current level of $150,000;[4]

[4] AEMC Reliability Panel, *Comprehensive Reliability Review, Final Report*, AEMC, Sydney, December 2007.

- EnergyAustralia's proposal to amend National Electricity Rule ("Rule") clause 3.14.6, which determines compensation to generators and NSPs during an administered price period (APP);[5] and
- A review of APC in early 2008 that led to an increase of APC to $300/MWh from the previous levels of $100/MWh and $50/MWh, for peak and off-peak periods, respectively.[6]

As noted at the start of this report, compensation arrangements, including Energy Australia's proposal, are discussed in a separate Concept report.

Conceptual assessment, theoretical analysis and NEM simulations are used to understand the drivers of recent historic high price events and, in turn, assess the risks associated with each of the other two proposed changes. Actual NEM price events are reconstructed, and scenarios are simulated to assess the impact of proposed increases in VoLL and/or CPT on risks faced by market participants. The overarching objective of the modelling analysis is to show how alternative VoLL-CPT settings would impact on market participants under extreme price conditions that may lead to financial stress.

What follows is a brief summary of the modelling framework employed for these analyses, followed by a summary of the key findings.

ANALYTICAL FRAMEWORK

As dictated by the terms of reference, the analytical framework has been designed to assess each of the following three key issues:

- **The impact of any changes to the VoLL-CPT arrangement on bidding behaviour.** The modelling undertaken comprises two components:
  - First, a conceptual and theoretical assessment of whether an increase in VoLL and/or CPT would encourage generators to bid more aggressively. Recent analyses, including studies conducted by the Australian Energy Regulator (AER), have identified aggressive bidding strategy during stressed system conditions as one of the key factors underpinning the majority of the recent high price events. A specific focus of the present study is to analyse how the proposed changes to VoLL/CPT might alter generator bidding incentives and affect risks faced by market participants. No previous study relating to VoLL/CPT setting has adequately explored its impact on generator bidding behaviour. A game-theoretic modelling framework is developed as part of this assessment; and
  - Second, empirical analysis, which compares and contrasts NEM price outcomes from alternative combinations of current and proposed VoLL-CPT scenarios, to quantitatively assess the risk that a change in bidding behaviour by generators and the combination of uncertain events in the NEM may lead to higher spot prices if VoLL and/or CPT are increased. This analysis implements the game-theoretic

5 EnergyAustralia, "EnergyAustralia's rule change request, Compensation provisions due to the application of an administered price, VoLL or market floor price", 10 December 2007.

6 AEMC, *Determination of Schedule for the Administered Price Cap*, Final Determination, May 20, 2008.

model for the NEM, in a way that explicitly captures the profit maximising behaviour of generators, given a CPT over a seven-day period.

- **Financial risks arising from price volatility**, i.e. whether the proposed increase in VoLL and/or CPT leads to a significant increase in price volatility arising from a combination of physical factors and market behaviour. The modelling exercise involves a comparison of spot price outcomes for a **base case**, where VoLL is $10,000/MWh and the CPT is $150,000, versus **three alternative scenarios**:

  - **VoLL is Increased:** The first scenario increases VoLL to $12,500/MWh, but holds CPT at the base case level;

  - **CPT is Increased:** The second scenario increases CPT to $187,500, but holds VoLL at the base case level; and

  - **Both VoLL and CPT are Increased:** The third scenario increases VoLL to $12,500/MWh and CPT to $187,500.[7]

  Comparing outcomes under the base case versus those alternative scenarios enables us to quantitatively assess the extent to which generators, retailers and MNSP/IRSR holders are likely to be affected by high prices and/or high price volatility, as a result of changing components of the VoLL-CPT-APC mechanism.

  The modelling analysis utilises a dispatch optimisation model, coupled with a Monte Carlo simulation model, to calculate spot prices and simulate a range of uncertain events to assess spot price volatility.

Similar to the previous two studies by the Reliability Panel in 1999 and Intelligent Energy Systems/ACCC in 2000, the market modelling analysis focuses on specific extreme events and scenarios, as it is under such extreme price conditions that risk management mechanisms are likely to be triggered and that market participants are likely to face financial stress. Two recent high price events in March 2008 and June 2007 are used to model proposed changes to VoLL and CPT, namely:

- March 11-17 in 2008, when SA had experienced a series of high price events that led to breaching the CPT on March 17 around 5:30 pm; and

- June 12-18 in 2007, when New South Wales (NSW) among other regions experienced very high prices with cumulative prices exceeding $120,000 for the week (despite the CPT not being breached).

These two weeks were chosen because recent analysis conducted by the AER suggests these two events are critical, in terms of developing insights about the key drivers of price volatility. In both instances, the AER analysis identified demand as one of the key drivers, but there were other related factors that significantly exacerbated price outcomes, including generator bidding.

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7 APC has been set at $100/MWh during peak and $50/MWh for off-peak for all three scenarios and the base case that prevailed in March 2008 and June 2007. Using the current level of APC of $300/MWh does not change any of the conclusions of the analysis. For instance, the worst case compensation payment for the extreme scenario (for SA) would be 2.4 per cent lower if an APC of $300/MWh were used. The differences for other cases are negligible.

SUMMARY OF FINDINGS

The following is a summary of key findings in respect of each of key the issues raised in the terms of reference.

"A conceptual assessment of the impact of the proposed increase in the levels of VoLL and CPT on financial risk to each participant class, including end users. In particular, the assessment should consider the current bidding behaviour of participants and how this behaviour would be expected to be modified by the proposed increase in the levels of VoLL and the CPT."

Our analysis suggests that increasing the levels of VoLL and CPT has the potential to modify generator bidding behaviour:

- Theoretical analysis and, to some extent, the limited evidence from recent high price outcomes, suggests that a binding CPT would influence the profit maximising strategy for generators. An inter-temporal bidding optimisation developed for the analysis provides the theoretical foundation for demonstrating how relaxing CPT would impact on the profit maximising equilibrium outcome in the market. Increases in the CPT provide greater opportunity for a generator to bid more aggressively. This not only affects peak prices but also off-peak prices. There are also indirect pricing effects for other regions that may not have a binding CPT.
- A simultaneous increase in both VoLL and CPT introduces a risk that generators can bid more aggressively – and for longer periods – without the risk of violating the CPT.
- We have also assessed qualitatively if a generator would likely adopt a strategy of breaching the CPT and maximising its gain from high spot prices leading up to the CPT *and* compensation payments. Given the significantly different incentives of bidding before and during an APP and the uncertain nature of events that lead to a breach, we believe it will be difficult – if not impossible – for a generator to adopt a strategy that *a priori* maximises the joint profit including compensation payments. A generator therefore is likely to avoid breaching a CPT, and instead will seek to maximise the profit from high prices while staying within the CPT. If uncertain drivers cause a breach of the CPT, depending upon compensation arrangements in place, generators may have a perverse incentive to bid aggressively *during an APP*. In particular, generators may have an incentive to offer a significant part of its capacity above the APC to maximise compensation payments paid to them.
- Although actual NEM experience is limited, the high price events during March 2008, and subsequent analysis by the AER, provide some evidence to suggest that generators in SA exhibited aggressive bidding behaviour in times of high demand and low interconnection. AER's analysis also suggests that, in some cases, generators showed a tendency to remain within the CPT rather than breach it, even when high demand provided them ample opportunity to breach the CPT.

"Market modelling to test the conceptual assessment described above and to provide further explanation of the financial risks to different participant classes."

Market modelling analysis augments the conceptual assessment. For reasons noted above, the market modelling reconstructed two high price events, in March 2008 and June 2007, to illustrate how a change in VoLL and/or CPT would impact under such extreme circumstances.

By the same token, the findings of our market modelling should be interpreted in this context only (i.e. only in the context of extreme events). For instance, if a price increase of (say) 20 per cent is reported for a VoLL/CPT scenario, it reflects how an increase in VoLL/CPT would impact on prices under such stressed conditions. This provides an objective assessment useful to understand the risk implications for a real-life event. However, such an outcome is not intended to be generalised to NEM price outcomes under normal conditions (i.e., average demand condition without major outages, etc). NEM prices in general will not in all likelihood increase by anywhere near 20 per cent for the vast majority of hours. The study is not intended to provide an average price forecast but assess the efficacy of risk instruments under extreme, low probability, events.

Although the market modelling was relatively simple (for instance, it ignored ancillary services) and had limitations on data for some of the uncertain drivers (such as, interconnection and gas system outage probability), we have been able to calibrate the model against the actual events reasonably well. Simulated prices reflect that these high price events may have resulted from the combination of generator bidding behaviour and stressed system conditions.

The base case results showed that a typical peaking generator (running on gas or oil) in SA/NSW would earn at least two-thirds of its annual fixed costs in the week before any occurrence of an APP. Although this is a significant fraction of annual fixed costs, it falls short of the 150 per cent of annualised capital cost that was intended in the initial setting of the CPT.[8] This study does not quantify the long term reliability implication of such a shortfall. Nevertheless, the fact that peaking generators do not earn sufficient net revenue to cover their annual capital requirement in the base case suggests a continuation of the **base case VoLL/CPT settings** may potentially lead to inadequate level of peaking investment to sustain NEM reliability standard. This seems consistent with the Panel's finding in the *Comprehensive Reliability Review:* "*….the analysis of future projections demonstrates that the USE reliability standard would be breached in the medium term at a level of VoLL of $10,000/MWh nominal*." This investment risk needs to be balanced against any price increase risk that may arise from an increase in VoLL and/or CPT;

Market modelling was then used to explore how an increase in VoLL/CPT would have caused generator behaviour and dispatch to affect prices. Market simulations for the four VoLL-CPT scenarios **for the two historic high price events** show that:

- Raising the CPT to $187,500, together with an increase in VoLL to $12,500/MWh, leads to a 20 per cent increase in cumulative prices overall relative to the base case for both NSW in June 2007 and SA in March 2008;
- In comparison, if VoLL is increased to $12,500/MWh but the CPT is retained at $150,000, SA prices in March 2008 would have increased by less than 1 per cent;

8 Reliability Panel's review of VoLL in 1999 had determined a CPT of $300,000 to "*allow a marginal supply side investment with a capital cost of approximately $400/kW to earn up to 3 times its annual capital requirement of $50,000/MW/year before the administered price is applied*". ACCC had subsequently determined the CPT to be set at $150,000 which allows for a return of 1.5 times (or 150 per cent) of annual capital costs.

- The combined impact of increasing both VoLL and CPT translates into an increase in total spot market purchase costs of $27 million in SA over March 11-17 in 2008 and $117 million in NSW over June 12-17, 2007. These additional spot purchase costs may add significantly to the burden for unhedged retailers;
- Increasing the VoLL alone raises the risk of breaching the CPT of $150,000 for both SA and NSW. A commensurate increase in the CPT to $187,500, along with an increase in VoLL to $12,500/MWh, reduces this risk to a level comparable to that in the base case (i.e., VoLL is $10,000/MWh and CPT is $150,000). However, as the preceding observations suggest, prices increase appreciably for both SA and NSW, reflecting a more aggressive bidding pattern by generators and, hence more frequent high price events; and
- The overall price impact across the NEM is not as significant. Thus, in March 11-17, 2008, an increase in VoLL and CPT would cause prices in SA to increase by $85/MWh for the week relative to the base case, whereas prices for the rest of the NEM increase by only $10/MWh. The price event in June 12-18, 2007 was more widespread due to energy limitations, including across QLD, SNY and VIC. An increase in VoLL-CPT therefore yields a higher $25/MWh impact across the NEM relative to the base case, compared to a $70/MWh price increase in NSW.

Risks arising from VoLL-CPT changes differ across market participants.

Generators face a mixed outcome if VoLL and/or CPT increases:

- If VoLL is increased to $12,500/MWh but CPT is retained at $150,000, the CPT is breached and prices are capped at APC for a significant number of periods. Maintaining CPT low relative to VoLL may adversely affect generator net revenue outcomes. If we ignore compensation (which should improve net revenues), a peaking generator would earn between 84 to 104 per cent of its annualised capital costs in a single week.[9] Therefore, even if the CPT is not raised, high prices leading to the point of breaching the threshold should generally provide generators with the bulk of the annual return needed to sustain their investment. Having said that, this return falls well short of the 150 per cent of annualised capital cost that was intended in the initial setting of the CPT.[10] There is clearly a trade-off in setting the CPT, and retaining the CPT at the current level will not serve one of the main goals that was set out to ensure adequate return to generators;

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9 Using capital cost estimates prepared by ACIL Tasman, *Fuel Resource, New Entry and Generation Costs in the NEM*, Final Report, September, 2007. ACIL Tasman estimates show that the annual capital requirements have increased from $50,000/MW/year used previously by the Reliability Panel in 1999/2000 to $56,000/MW/year and is projected to rise to $81,000/MW/year (in nominal terms) over the next 20 years.

10 Reliability Panel's review of VoLL in 1999 had determined a CPT of $300,000 to "allow a marginal supply side investment with a capital cost of approximately $400/kW to earn up to 3 times its annual capital requirement of $50,000/MW/year before the administered price is applied". ACCC had subsequently determined the CPT to be set at $150,000 which allows for a return of 1.5 times (or 150 per cent) of annual capital costs.

- The frequency of a CPT breach increases significantly if the CPT is retained at $150,000. In the long term, if the current CPT persistently mutes the effect of a higher VoLL, this will discourage peaking investment, especially if the current trend of escalating generation capital cost continues in future. If adverse weather conditions recur and some planned capacity additions are delayed, or abandoned, the NEM reliability standard may be jeopardised (as the Comprehensive Reliability Review study has shown); and

- In contrast, if both VoLL and CPT are increased, this creates an upside for generators that may encourage investment. An increase in super peak period prices alone, which are defined as the top 7.5 hours when prices are above $1,000/MWh, would have earned NSW and SA generators an additional $13,000 and $7,500 per MW in net revenues for June 12-18, 2007 and March 11-17, 2008, respectively. These represent 20 per cent and 12 per cent of annualised fixed costs for a new green-field peaking generator which will encourage peaking investment. The overall price increase adds considerably more to the net revenue. SA generators could expect an average increase in net revenue of $124/MWh over the March 11-17 week, while NSW generators could expect an increase of $79/MWh over June 12-18.

Retailers and other wholesale market energy purchasers are likely to be adversely affected:

- Retailers would face a significant spot price increase during peak periods, including super peak periods. On average, prices increase by 20 per cent, and the increase over the top 7.5 hours alone amounts to an additional VoLL event for the week studied. The overall cost increase for an unhedged retailer in the short term translates into $13,000 – $14,000 per MW (or, $13-$14 per kW) for a retailer in SA depending on its load shape;

- If the retailer is able to pass the increase in costs to final consumers, the cost will ultimately be borne by these customers.[11] However, the added cost over a longer period will be far less significant, as may be illustrated for a typical residential customer (say) with a 2.5 kW load. An increase in cost of $13-$14 per kW will cost the load an additional $33-$35 per year if one of these events occurs every year. Assuming an annual electricity bill for a typical customer to be $1,000, this implies approximately a 3.5 per cent rise in electricity bill for an average customer if one of these events were to recur in a year. If we assume these extreme price events are likely to be less or more frequent, the impact will be lower or higher. For instance, if we assume a breach to be a 1-in-5 year event, the price impact will be less than 1 per cent; and

- In the long term, a retailer without appropriate hedge cover may also face some financial consequences because each extreme price event may potentially wipe out a significant part of its net revenue margin for a year. Even if the retailer has hedged its risk against peak prices, the increased volatility will increase contract prices over time, albeit the cost impact will be far less onerous compared to the short term impact faced by an unhedged retailer.

[11] There will be regulatory risks that may or may not allow such pass through.

Participants with exposure to inter-regional price differences (namely, scheduled NSPs, including market NSPs and inter-regional settlement residue unit holders) will generally experience a rise in inter-regional price differentials:

- Simulation results show that the SA-VIC price differential for super peak periods (i.e., when SA prices were above $1000/MWh) increases from approximately $6,000/MWh in the base case to nearly $7,500/MWh under the alternative scenario in which both VoLL and CPT are increased. The price event in June 2007 was much more widespread than the price event in March 2008 because it was driven by water restrictions in most parts of the NEM. A high VoLL-CPT in the presence of a widespread energy limitation does not necessarily increase the inter-regional price difference, nor produce any discernible pattern for risk assessment to MNSP/IRSR.
- During an APP, scaling back regional prices may drastically change price differences, and may even reverse prices across regions in some cases. However, these do not create significant risks for MNSP/IRSR unit holders because of the much lower prices during an APP.

CONCLUDING REMARKS

Our analyses as well as (limited) recent experience with extreme high price events suggest that it is the combination of aggressive generator bidding under stressed system conditions (driven by physical factors such as high demand and limited generation availability) that drives high price events, rather than physical factors alone.

Increasing VoLL and the CPT provides generators with greater latitude to bid more aggressively without the risk of breaching the (higher) CPT. Market simulations of two recent high price events reveal that, if both VoLL and CPT are increased, (cumulative) prices may rise as much as 20 per cent on an already high level for the selected weeks. Under extreme system conditions that prevailed in recent months, an increase in VoLL and CPT will add significantly to the energy purchase cost risk faced by a retailer. Prices in general over a longer period, e.g., annual average prices, will not be affected as much because such extreme events are expected to occur infrequently. Assuming retailers pass on the added costs to final customers, a typical customer bill can be expected to increase by 3.5 per cent if an extreme price event occurs every year, or less if such events occur less frequently – for instance, less than 1 per cent if such extreme events occur once in every five years.

On the other hand, if VoLL alone is increased without a commensurate increase in the CPT, generators face the prospect of a lower revenue outcome. Although generators are able to recover most of its annualised fixed costs, the net revenue falls well sort of the 150 per cent of annual capital requirement that was intended to be one of the criteria in determining the CPT. If the CPT is retained at $150,000 and VoLL is raised, this also materially increases the risk of breaching the CPT.

The final selection of CPT and VoLL needs to strike a balance:

- If both CPT and VoLL are raised, there is the potential for an increase of up to 20 per cent in spot prices if an extreme price event such as those in March 2008 or June 2007 were to occur. This translates into a 3.5 per cent increase in an average customer's annual bill if one of these events occurs in a year, and less than 1 per cent if it occurs once every five years. A commensurate increase in CPT with VoLL maintains the risk of a CPT breach at approximately the same level as the current level.
- If CPT is retained at $150,000, but VoLL is raised, a typical peaking generator recovers the bulk of its annual fixed costs, but falls well short of the 150 per cent of annual capital requirement criterion that was set out by the Reliability Panel/ACCC in 1999-2000. Retaining the CPT at $150,000 also substantially increases the risk of breaching the CPT once VoLL is raised.

1. INTRODUCTION

In an energy-only market such as the Australian National Electricity Market (NEM), volatility of spot prices for both energy and ancillary services is an essential ingredient of the market design and operation. It is needed for generators and other forms of investment to earn a reasonable return on their assets and recover their fixed costs. However, it also creates risks for wholesale market purchasers, because a persistently high spot price can cause extreme hardship and may jeopardise the existence of the market in an extreme case. While individual market participants should use their prudence to manage their risks to suit their appetite for risk, the market design includes some "safety valves" to manage extreme price risks that may lead, for instance, to the financial failure of several retailers and potentially other participants in the market. NEM design has evolved over the years in this area and currently has four mechanisms in place to limit the risks arising from sustained high prices:

- A spot price cap known as the value of lost load (VoLL) and a price floor;
- A cumulative price threshold (CPT) that applies over a rolling seven day period and that triggers an administered price period when breached;
- An administered price period (APP), during which an administered price cap (APC) applies to settlements in the region where the CPT was breached, while settlement prices in other regions exporting towards the APC region are scaled back towards the APC level using the average loss factors on each interconnector; and
- A compensation mechanism for eligible parties (generators, scheduled loads, MNSPs, IRSR unit holders) that are affected during the APP.

These four elements comprise an overall package within the Rules for managing the risks that sustained high prices could pose to the solvency and viability of the NEM and its participants. This package was conceived by the Reliability Panel and NECA in 1999-2000, and approved by the ACCC in 2000. This package of measures replaced the Force Majeure (FM) provisions that had existed prior to that date, and which were meant to address the same issue.

These four instruments are intended to be used in such a way that balances out risks faced by all participants. There is inevitably a trade-off among risks faced by different participants. For example, retailers face a high spot energy purchase cost while a generator with a peaking investment would face a revenue risk at the same time. The key to successfully managing these risks is to choose levels of VoLL, CPT and APC, and a basis for compensation, that strike a balance between the potentially conflicting interests of the various market participants. Importantly, changing one of the components (e.g. increasing or decreasing VoLL) alone may not deliver such a balanced outcome.

In last ten years of NEM operation (1998 through to 2008), the extreme prices that could trigger a breach of the CPT have rarely occurred. Indeed, by definition, such extreme events are supposed to be a rarity. The design settings for VoLL, CPT and APC have gone through periodic reviews, but have not been altered for a considerable period. However, a series of high price events over the last 12 months has renewed interests in these settings. There are a number of proposed changes to the settings of VoLL, CPT and APC that have been discussed recently, including:

- The AEMC review of the level of the APC in early 2008 — which has resulted in the APC rising to $300/MWh at all times, from the $150/MWh peak and $50/MWh off-peak levels that had previously prevailed since 1998; [12]
- The Reliability Panel's December 2007 final report on the Comprehensive Reliability Review recommending increases in VoLL to $12,500/MWh from the current level of $10,000/MWh and the CPT to $187,500 from the current level of $150,000; [13] and
- A Rule change proposal by EnergyAustralia that seeks to change the basis of compensation during APPs.[14]

These proposed changes have been made or suggested against a backdrop of concerns over the effects of the sustained drought on reliability and prices in the NEM at times of high demand.

Any changes in the settings of VoLL and the CPT (and compensation during APPs) change both the risks faced by the participants and the incentives to invest that are critical to the maintenance of reliability.

Past reviews of VoLL and CPT do not provide an adequate guidance in understanding the dynamics, risks and outcomes of recent pricing events that have come close to or have in fact breached the CPT because the analysis that went into such reviews was limited in one or more of the following respects or another. This largely reflects the fact that some of these assessments were done:

- At an early stage of the NEM operation, when there was limited history and experience on price volatility; and
- Under relatively more benign system conditions than exist at present. Demand has grown considerably over the last ten years, absorbing any spare generation and transmission capacity. At the same time, new conditions have emerged that have tightened the supply-demand balance — such as extreme demand volatility, limited hydro availability, and a greater frequency of binding transmission network capacity limits.

Moreover, reviews of VoLL and the CPT since 1999-2000 have generally focussed on the reliability impacts of changes in the levels of VOLL and CPT. While the financial risks arising from such changes have been recognised, there has been very little analysis of the financial risk impacts of changes in VoLL and the CPT. This is not surprising, given the focus of the Panel on reliability impacts, and the fact that extreme price volatility threatening a CPT breach rarely occurred.

However, the need for a comprehensive assessment of risks faced by participants has now been identified by the Reliability Panel because of the recent change in circumstances and the range of proposed changes to individual elements of the VOLL, CPT, APC, APP-compensation package.

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[12] AEMC, *Determination of Schedule for the Administered Price Cap*, Final Determination, May 20, 2008.

[13] AEMC Reliability Panel, *Comprehensive Reliability Review, Final Report*, AEMC, Sydney, December 2007.

[14] EnergyAustralia, "EnergyAustralia's rule change request, Compensation provisions due to the application of an administered price, VoLL or market floor price", 10 December 2007.

The AEMC has asked Concept Economics ("Concept") to provide a written report to the Reliability Panel ("the Panel"), on the impacts of proposed increases in VoLL and CPT. In particular, the AEMC has requested that the report address the following key issues:[15]

- *The financial risk faced by participants in the National Electricity Market ("NEM");*
- *The level of systemic, market-wide risks; and*
- *The efficiency and efficacy of the packages of VoLL, CPT, Administered Price Cap (APC) and compensation arrangements and their settings in mitigating systemic, market-wide risk at times of extreme financial stress.*

This report examines each of the issues raised in the AEMC's terms of reference, aside from alternative compensation arrangements. Alternative compensation arrangements, including proposals regarding compensation put forward by EA, are examined in detail in a separate Concept study.[16]

Accordingly, this report provides a conceptual assessment to understand the behaviour of prices and the factors that drive such high prices, including generator bidding behaviour under stressed system conditions. This conceptual assessment is complemented by market modelling of the key recent high price events in order to quantify the risks arising from the Reliability Panel's proposed changes in the levels of VoLL and the CPT.

1.1. STRUCTURE OF THE REPORT

The structure of the remainder of this report is as follows:

- Section 2 of the report provides the relevant NEM context for this study, including background information on the VoLL-CPT-APC mechanism, recent history of high prices, as well as a summary of previous analyses conducted in relation to the setting of VoLL-CPT;
- Section 3 sets out the modelling approach we have adopted for assessing the risks associated with changing the CPT and VoLL;
- Section 4 contains the results of the modelling undertaken; and
- Section 5 summarises the findings of the study.

Appendix A to Appendix D contain additional background details, including a technical description of the model and modelling assumptions.

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15 Appendix A includes the terms of reference for the study.

16 Of course, as is apparent from the discussion in this report, there is a close interrelationship between compensation and other aspects of risk management. Hence, it is necessary in parts to discuss issues relating to compensation. That said, an analysis of specific compensation arrangements is beyond the scope of this particular report.

2. NEM DESIGN AND INSTITUTIONAL CONTEXT

This section describes the relevant NEM context that provides the underlying motivation for the modelling analysis undertaken in this study. In particular, we discuss:

- Why volatility is an essential component of the NEM;
- Provisions in the NEM design that are in place to contain *extreme* price volatility risks, and also general risk management options commonly used by market participants to guard against price volatility;
- Shortcomings of previous studies that have analysed VoLL and CPT setting, most notably, the fact that these studies ignore the interrelationship between VoLL-CPT and the generator bidding behaviour; and
- Recent high price events, which highlight the importance of generator bidding behaviour.

2.1. MARKET RISKS

The NEM is an energy-only market. That is, generators submit supply offers on a $/MWh price and are paid the uniform regional market clearing price for their output. Retailers and large customers purchasing from the spot market must correspondingly pay the regional market clearing price for any energy they purchase. The specific characteristics of electricity give rise to significant short term price variations and price volatility, which in turn create risks for all market participants. In order to limit the financial risks on the buying side, the NEM rules incorporate a number of mechanisms that limit high price risks, but these pricing rules may affect investment incentives, as well as potentially create incentives for market participants to alter their bidding strategies at certain times.

All electricity wholesale markets must address two essential market characteristics that necessarily follow from the physics of electricity, which are that:

- The supply side cannot store its output. There are then circumstances when demand is unusually high or when generation/transmission outages occur, and when demand cannot be met; and
- On the demand side, with few exceptions, customers are highly unresponsive to short term prices, and will not/cannot reduce demand in response to very high prices. In addition, the flow of power to individual customers – or the reliability with which individual customers are supplied – cannot be controlled.

In combination, this means that there are circumstances when consumers effectively demand electricity no matter what the price, and no market clearing price in the classical sense exists. The solution to this problem is a core feature of the electricity wholesale market design: under certain circumstances, the system operator intervenes to set a regulated price limit.

In combination, these factors create considerable financial risks for market participants. All market participants, be they on the buying or on the selling side, face spot prices that are essentially volatile and responsive to (very) short-term market events. Generators face a risk of low prices impacting on earnings, while on the buying side, retailers (on behalf of small customers) and large customers are exposed to very high price events that can potentially lead to “infinitely” high spot prices if the market is not artificially cleared. There are related indirect risks, for instance, caused by the influence of spot prices on contract prices, cost of insurance, etc. that also affect market participants.

A number of mechanisms to manage these high price events for both sides of the market (discussed in Section 2.2 below) have therefore been put in place in the NEM. While these mechanisms help to contain risks, they are at best limited options, in part because many of them are left to the choice of individual participants. Sustained extreme price events can expose market participants to severe risks. As electricity market failures elsewhere have shown, persistently volatile prices can cause extreme financial hardship to retailers and extreme measures to curb such volatility (e.g., setting a very low price cap) have dried up investment in generation. Although these impacts may be localised in some cases, restricted to one region or even an individual participant, there are often cascaded effects with a series of financial failures leading to a systemic market risk.

The focus of this study is extreme high price events and “rule based” risk instruments to contain such risks. High price events, as we have discussed at length below, can stem from two broad drivers, namely, physical sources and market behaviour. Physical sources may include a shortage of generation/transmission capacity/energy or an unforeseen surge in demand caused by a heat or cold wave. Shortage of capacity/energy may be driven by a wide range of factors, from a chronic lack of investment through to short term outages on generation/transmission/fuel system, or drought conditions.[17] Depending upon their contract position, size and state of the system, generators may have a varying degree of influence on market prices, especially under stressed system conditions, such as a shortage of capacity or unusually high demand.

While high prices are a source of financial risk to retailers, expected market prices and profits from generation are central to driving investment. The NEM market design does not incorporate additional payments for generation capacity or availability, and generators must recover the fixed (capital) costs of plant from differences between the market clearing price and their variable generating costs, referred to as short-run profit, scarcity rent, or “infra-marginal rent”.[18]

17 Not all forms of physical risks can be, or should be, contained by rule based mechanisms. A chronic investment problem or a catastrophic disruption of fuel supply, for example, are sources of risk that are beyond the control of the electricity market and will need a wider policy intervention that goes beyond the scope of mechanisms we discuss here.

18 There are two provisos to this statement. The NEM has separate markets for a range of ancillary services, some of which are now integrated with the energy market. Generators can earn additional revenues through sales of ancillary services, but at least for baseload/intermediate plant, such revenues tend to be immaterial compared to revenues from energy sales. NEM generators can elect to sell their output via the spot market or via the contract market. However, these markets are intimately linked, and in the medium to longer term, average price outcomes in both markets would be expected to be the same.

As a typical regional price duration curve in the NEM for any year reveals, the inframarginal revenue that a peaking plant could expect to earn during a particular year varies enormously depending on the number of price spikes. These spikes, which we have referred to as "super peak", may provide a significant part of revenue available to pay for the plant's fixed costs. A generator faces a "net revenue" risk, in that it recovers its fixed cost only when market prices are above the plant's variable cost. From the perspective of investors – especially in peaking plants – price volatility is essential for them to recover their costs and this is a crucial risk issue that also needs to be adequately addressed in determining any price cap.

2.2. RELEVANT NEM MARKET DESIGN MECHANISMS

In combination, supply and demand characteristics of wholesale electricity markets require regulatory determinations of price limits to deal with circumstances when the market cannot clear, or where prices are such that the resulting financial consequences would materially undermine the continued operation of the market and its participants. That regulatory policy determines the magnitude and also the duration of price spikes.

The National Electricity Rules contain a number of key mechanisms that are designed to limit risks to individual market participants and systemic market wide risks.[19] VoLL, CPT, APC and Compensation in combination with the market floor price, define the price envelope within which supply and demand are balanced in the wholesale spot market, and capacity is delivered to meet the NEM.[20] The background to and operation of these mechanisms are briefly described below.

2.2.1. VoLL

VoLL is currently set at $10,000/MWh, and has been set at this level for several years. VoLL is a crucial market parameter because it provides signals for supply and demand-side investment and usage. For example, if the cap is set too high, consumers (either via their retailers or trading directly in the market themselves) can be financially exposed. If the cap is set too low, there may be insufficient incentives to invest in new generation capacity to meet future reliability due to the risk of fixed costs not being able to be adequately recovered.

Under the current Rules, the Reliability Panel is required to conduct a review of VoLL, the market floor price and the CPT by 30 April each year.[21] A review of the level of VoLL in 1999 resulted in the increase to its current level from $5000/MWh. In its 2006 and 2007 determinations, the Panel did not alter the level of those parameters, pending their examination as part of a Comprehensive Reliability Review. Following that review, the Reliability Panel recommended incrementally lifting VoLL to $12,500 from 1 July 2010.

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19 In addition to the "direct" risk management mechanisms that we discuss here, there are other indirect mechanisms in place that also help mitigate financial risks, namely prudential requirements, designated retailer of last resort for retailers, and settlement rules that limit collection risk.

20 The market floor price is a price floor on regional reference node prices. The current value of the market floor price is -$1,000/MWh.

21 Rule 3.9.4.

2.2.2. The CPT

The CPT is an automatic trigger defined in the National Electricity Rules for initiating an APC period. Under the current arrangements an APC is invoked by NEMMCO if the cumulative half-hourly price over a seven day period exceeds $150,000, corresponding to an average spot price of approximately $446/MWh over the seven previous days.

The CPT was designed to replace previous *force majeure* triggers based on load shedding events. It was introduced into the National Electricity Code in December 1999, following a recommendation by the NECA Reliability Panel in July of that year to apply the CPT as a primary mechanism for capping risk to market participants. NECA had submitted a number of changes for authorisation, including an increase of VoLL in two steps to $20,000/MWh, a CPT of $300,000, a peak period APC of $300/MWh and an off-peak period APC of $50/MWh. Reliability Panel's suggestion to set the CPT at $300,000 was to "*allow a marginal supply side investment with a capital cost of approximately $400/kW to earn up to 3 times its annual capital requirement of $50,000/MW/year before the administered price is applied*".

In July 2000, ACCC made a determination to increase VoLL to $10,000/MWh and set CPT at $150,000, which allows for a return of 1.5 times (or 150 per cent) of annual capital costs.

In December 2007, the AEMC released the final report of the Comprehensive Reliability Report which in part examined the current operation of the CPT and VoLL arrangements. This report considered the current level of the CPT and whether the financial threshold provided by the CPT should be augmented by a physical trigger. The report recommended that the CPT should be lifted to $187,500 from 1 July 2010 to maintain a 15:1 ratio between the CPT and VoLL.

2.2.3. The APC

An APC is a regime triggered by a number of conditions set out in the Rules, including circumstances in which the CPT has been breached.[22] Under current arrangements, an APC is invoked once the CPT breaches $150,000. The APC applies in regions undergoing extreme market events, and automatically sets the price of dispatch to a value determined by the AEMC. Once invoked, the relevant trading periods become 'administered pricing periods' (APP). This cap applies at least until the end of the current trading day.

The rules provide for the AEMC to publish and update a schedule of APC values.[23] The schedule for the APC was amended by the AEMC in May 2008, where it was set at $300/MWh for all regions in the NEM, for all time periods.

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22 See National Electricity Rules 3.14.1-3.14.2. http://www.aemc.gov.au/electricity.php?r=20071105.151356.

23 http://www.aemc.gov.au/electricity.php?r=20071106.104606.

2.2.4. Compensation Arrangements

The generator compensation arrangements allow scheduled generators to seek compensation when their offer price for any cleared offer during an APP is higher than the APC. "Constrained-on" generators with offer prices higher than the APC are eligible for compensation if the resultant spot price payable to dispatched generating units in any trading interval is less than the price specified in their dispatch offer for that trading interval.[24] Other market participants that can also claim compensation following an APC are Scheduled Network Service Providers, Market Participants, and ancillary service generating units and loads. Compensation is determined by the AEMC based on advice from an expert panel.

The AEMC is in the process of considering a Rule change proposal relating to these compensation provisions submitted by EnergyAustralia ("EA"). As noted above, issues relating to compensation are discussed in a separate Concept report. That said, as will be noted shortly, there are close interrelationships between compensation arrangements and other components of the overall risk management package.

2.2.5. Implications of NEM Market Design Mechanisms for Market Participants

Briefly summarising the interrelationship between CPT, APC and Compensation arrangements:

1. If half-hourly prices in a region on a rolling 7-day basis exceed the CPT, an APP is declared with prices in the region is capped to the APC. Prices in other regions exporting to the region are scaled back using an average loss factor to avoid all instances of negative inter-regional settlement residues;[25]

2. Dispatch during an APP continues to be calculated based on the normal procedure using bids/offers and an uncapped, or normal, spot price is also calculated. The uncapped spot price is used to compensate eligible market participants.[26]

As a package, these instruments are intended to strike a balance between containing extreme price risk for those who buy energy, while, at the same time, providing liberal allowances to ensure that investment in peaking generation is not curtailed. In fact, the original proposal from the Panel was to set the CPT high enough for a peaking generator to recover up to 300 per cent of its annual capital requirement but this was subsequently reduced to 150 per cent. During an APP, the APC is set for all generators (including those at the expensive end) to recover their operating costs.

While these instruments attempt to contain market wide risk, they also create dispatch/pricing anomalies that have adverse consequences, namely that:

- First, dispatch and settlement prices are no longer aligned, which may distort economic signals and affect generator behaviour; and

24 See National Electricity Rules, Clause 3.14.6.

25 Rule 3.14.2(e).

26 As defined by Rule 3.14.6.

- Second, prices and dispatch in regions that do not have a binding CPT are affected because of the price scaling.

Application of APC affects all market participants, including:

- Generators, because it lowers their revenue and creates uncertainties on recovery of fixed costs;
- Retailers, because it increases their spot purchase costs in the short term and costs of hedges in the long term;
- Scheduled NSPs, who are exposed to inter-regional price differences; and
- Traders, who take position on arbitrage opportunities.

2.3. PARTICIPANT RISK MANAGEMENT MECHANISMS

In addition to the mechanisms described above, which form a fundamental part of the NEM design, market participants can purchase financial instruments (derivatives and insurance) to manage price risks.[27]

The most common forms of these instruments in the NEM are:

- Forward contracts (swaps or futures),
- Options,
- 'Cap' and 'floor' contracts,
- Future options or 'swaptions' - an option to enter into a swap/futures contract at an agreed price and time in the future,
- Asian options – an option where pay offs are linked to the average value of an underlying asset such as the NEM spot price, and
- 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.[28]

Participants can also diversify their portfolio across counterparties and by having load offset generation within a physical portfolio. Another option available to participants is to use their own balance sheet or other forms of credit support or debt facilities to manage risks to cash flows.

Other mechanisms for managing price risks in the NEM include:

- Vertical integration across the generation and retailer sectors. Vertically-integrated firms are thought to account for about 14 per cent of installed capacity across the NEM;[29]

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27 AER, *State of the Energy Market 2007*, July 2007.

28 AER *ibid*, Table 3.1, p.102.

29 AER, *ibid,* p.110.

- In NSW, the Electricity Tariff Equalisation Fund (ETEF) provides a hedge against NEM prices spikes for government-owned retailers; and
- Auctions of settlement residues to allow for the management of inter-regional price risks.

2.4. PREVIOUS STUDIES ON VOLL AND CPT SETTINGS

There have been three previous studies that have analysed the setting of VoLL and CPT levels. It is useful to summarise the key attributes of these three studies in order to better understand the need for the present study:

- The Reliability Panel's Modelling on VoLL and CPT (1999) was conducted as part of its initial recommendation on VoLL and CPT setting. The modelling was relatively simple, relying upon spreadsheet–based analysis of prices over a 24 hour period. Typical high price events were simulated and the adequacy of VoLL/CPT settings to provide adequate return to a new entrant peaking open cycle gas turbine plant was assessed. The study did not undertake any detailed market simulations or any analysis of bidding behaviour and probabilistic outages.
- An Intelligent Energy Systems (IES) Study, commissioned by the ACCC as part of the authorisation of NECA's proposed Code changes, employed market simulations as part of its assessment for a representative region, which is understood to resemble Victoria in the year 2006. The study took into account alternative generator bidding behaviour and a set of pre-determined extreme outage scenarios to assess the impact of VoLL and CPT. In particular, the study focused on the effectiveness of CPT to contain risk under extreme bidding and outage scenarios. While this study marked a major improvement on the Initial Reliability Panel study in 1999, the IES study did not consider any connection between VoLL/CPT setting and generator bidding behaviour and it relied on deterministic generation outages rather than a probabilistic simulation of multiple factors that may lead to high prices.
- The CRA International Comprehensive Reliability Review (2007) undertook a detailed multi-year probabilistic market simulation of the NEM to assess alternative reliability mechanisms. Alternative levels of VoLL as well as reserve market arrangement scenarios were simulated. Although the study is a further improvement on the IES study in some respects, such as a NEM-wide multi-year projection that includes optimised capacity addition, the CRA study also did not consider the interaction between bidding and CPT and had a limited set of uncertain variables (e.g., it did not consider uncertainties around hydro and gas availability).

Further details on these three studies are included in section Appendix B.

To summarise, VoLL and CPT modelling has evolved from the relatively simple modelling approaches adopted in the initial establishment of these mechanisms, to increasingly sophisticated models that take into account a wider range of factors.

However, an important feature of *all* of these previous modelling exercises is that they did not include the impact of any changes to the VoLL-CPT arrangement on generator bidding behaviour. This potential incentive for participants to alter bidding behaviour has been recognised as one of the drivers of price risks in the NEM, as we note in the following sub-section, and is a major focus of this report.

2.5. RECENT HIGH PRICE EVENTS IN THE NEM

The NEM has seen a number of high price events over the last year. The AER has undertaken an analysis to identify the factors that played a material role in the context of recent high price incidents when the CPT has been breached or has come close to being breached.[30] While the CPT has only been breached once since NEM commencement (on 17 March 2008 in SA, as described below), there have been four other occasions when the CPT has been close to breaching the $150,000 threshold, namely:

- From 12 to 28 June 2007 in NSW, when the rolling seven day price reached $135,000;
- On 11 January 2008 in SA, when the rolling seven day price reached $138,000;
- On 19 February 2008 in SA, when the rolling seven day price reached approximately $143,000; and
- On 23 February 2008 in Queensland, when the rolling seven day price reached $144,000.

The AER found that a combination of *two or more* factors are required to drive the cumulative price towards the CPT, and that four key factors contributed to a CPT breach, namely:

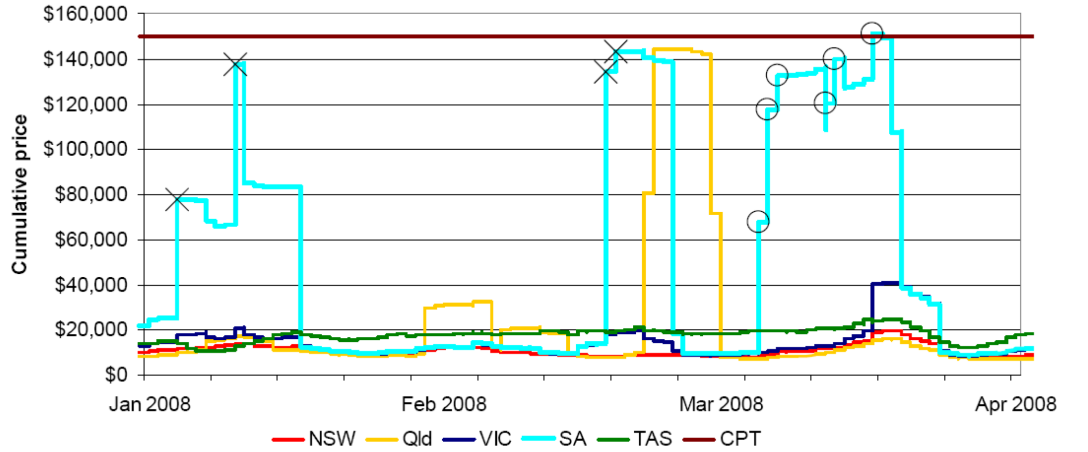
- High demand levels, arising from extreme high or low temperatures;
- Binding interconnector constraints or the loss of an interconnector;
- Bids close to VoLL by generators (especially large base load units); and
- A lack of generation capacity availability.

At the same time, predicting events such as an interconnector constraint or outage is complex and depends on the interaction of multiple factors. Modelling the likelihood and impact of events leading to a breach of the CPT must therefore incorporate the combination of extreme and unpredictable events, and reflect their subsequent market outcomes. Additionally, any modelling must capture the fact that generator availability is affected by a number of factors, including maintenance strategies, as well as different types of energy constraints (possibly in combination with water restrictions).

30 AER, *ibid*.

The Australian Energy Regulator (AER) has also undertaken an analysis of the CPT breach that occurred in SA over the period of 5 to 17 March 2008.[31] Chart 1, reproduced from the AER report, shows the seven day rolling cumulative price for all NEM regions together with the CPT of $150,000. The graph shows that the cumulative price was close to the threshold for the whole period of the heatwave, before being breached at 5 pm on 17 March. Over the relevant period in March 2008, spot prices in SA exceeded $5,000/MWh on 26 occasions. Average spot prices in March were $325/MWh, the highest-ever monthly price since the market started in 1998.

Chart 1 **Seven Day Rolling Cumulative Price and CPT**



Note: The six high priced days covered by this report are circled in the graph. The other four days, when the spot price in South Australia exceeded $5000/MWh, occurred earlier in the year (and are covered in a separate AER report). These are marked with a cross.

Data source: AER, "Spot prices greater than $5000/MWh, South Australia: 5 - 17 March 2008". May, 2008.

The AER also found that there were a number of contributing factors to the high priced events in South Australia, most notably the fact that SA was in the midst of an extended heatwave that created unprecedented levels of electricity demand. However, the AER identified additional factors that combined with high demand to contribute to the high price events, namely, bidding behaviour on the part of a market participant, as well as a lack of network availability, in particular in relation to the import limit into SA from VIC.

2.6. IMPLICATIONS FOR THIS STUDY

These recent high price events, the limitations of previous studies, and the wider context of the reviews currently being undertaken by the AEMC, provide the motivation for further analysis of financial risks in the NEM. Specifically, the modelling analysis outlined below examines:[32]

1. **The impact of any changes to the VoLL-CPT arrangement on bidding behaviour by participants.**

The following issues provide the necessary context for the present study:

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31 AER, "Spot prices greater than $5000/MWh, South Australia: 5 - 17 March 2008".

32 Modelling analysis of alternative compensation mechanisms is beyond the scope of this particular report.

- As just noted in the discussion of recent high price events, market participant bidding behaviour has been recognised as one of the drivers of price risks in the NEM. We therefore explore the implications of alternative combinations of current and proposed VoLL-CPT parameter settings to assess whether a change in bidding behaviour by generators, in combination with incidence of uncertain events in the NEM, may lead to higher spot prices if VoLL-CPT is increased.
- This study in a way complements the CRR study by explicitly incorporating generator bidding behaviour including a CPT limit that may discipline such behaviour.
- The present study has a clear focus on extreme (price) event and explores “what if” scenarios around design parameter change. This is the same approach adopted in the previous studies of VoLL-CPT, including the Reliability Panel 1999 and IES/ACCC 2000 studies. In other words, all of these studies focus on the impact of VoLL and CPT settings on prices under extreme events, rather than seeking to predict such an event.
- Since these events are by definition low probability events, it would be impractical to model every single half-hour in a year because vast majority of these periods will not exhibit extreme price risks. Instead, as detailed below, two recent high price events in March 2008 and June 2007 are used as the basis of the modelling undertaken. Having a focus on the recent high price events is useful because it helps to understand the drivers of these price events better. More importantly, it provides a way to answer some critical questions as to what would have happened under these circumstances if VoLL-CPT are increased. In selecting these price events, we have selected events that cover the major physical drivers including one event that is a localised high price event in a single region and the other that is much more widespread across several regions.

2. **The financial risks arising from price volatility – that is, whether the proposed increase in VoLL-CPT would lead to a significant increase in price volatility as a consequence of a combination of physical factors and the behaviour of market participants (especially generators).**

   To address this issue, we compare spot price outcomes across NEM regions for different time periods and alternative VoLL-CPT scenarios to identify if generators, retailers and MNSP/IRSR holders are likely to be affected by high prices and/or high price volatility.

3. MODELLING APPROACH

Our modelling approach has the objective of addressing those two key issues just noted. The modelling approach also has more general regard to the terms of reference, which highlight that:

- The relevant financial risks are broad in their origin and include fuel supply issues;
- An assessment of financial risks needs to incorporate all market participants, from investment risks for generators to revenue and cost risks faced by MNSPs and retailers; and
- The efficacy of the *total package of risk mitigation measures* i.e., VoLL-CPT-APC (and Compensation), needs to be assessed.

The terms of reference also suggest that an increase in VoLL and/or CPT may influence generator bidding behaviour. To the extent this is the case, spot prices increase, and such effects would add to financial risks faced by market participants. In turn, a systemic increase in risk faced by participants may have far reaching consequences for the market. Therefore both physical factors and generator bidding behaviour need to be studied. In order to mitigate such risks, APCs are set at a substantially lower level than VoLL apply in the NEM.

The analytical framework used to analyse the risk issues has two major inter-related components:

- First, a **conceptual and theoretical assessment** of some of the key issues that inform the formal market modelling analysis. Specifically, we examine the linkage between VoLL/CPT/APC and generator bidding behaviour. A specific focus of the present study is to analyse how the proposed changes to VoLL/CPT might alter generator bidding incentives and affect risks faced by market participants.
- Second, a **market modelling analysis** that takes into account physical and behavioural drivers of prices, including market design parameters such as VoLL-CPT-APC-Compensation, to quantify price and other risks associated with increasing VoLL and/or CPT above current levels.

3.1. CONCEPTUAL ASSESSMENT

This section conceptually analyses two key issues that are of interest:

- Sub-section 3.1.1 examines the relationship between the CPT and compensation, and incentives this provides with respect to generator bidding behaviour; and
- Sub-section 3.1.2 qualitatively assesses the financial risks faced by market participants.

3.1.1. Intertemporal Modelling of the Cumulative Price Threshold

Compensation arrangements are not the focus of this report. However, as will be explained, the interrelationship between CPT and compensation is likely to have implications for generator bidding behaviour, and therefore informs the adopted modelling approach.

For each generation “player” (which may be an individual generator or a portfolio generator), the intertemporal optimisation model solves for optimal conditions for an entire day/week to maximise the overall profit over the entire timeframe, e.g., across the entire week.[33]

Breaching the CPT leaves the generator facing the prospect of market prices set on the basis of an APC and a compensation payment. Depending on the compensation arrangements put in place, the latter may vary from its direct operating costs to its offer price. In theory, offer prices may negate the effect of the CPT and enable the generator to earn effectively what it could earn absent the CPT, making the generator indifferent over whether or not to breach the CPT. However, in practice, generators will likely prefer not to breach the CPT, for the following reasons:

- Compared to a certain spot price revenue before the CPT is breached, compensation outcomes are uncertain. Specifically, compensation outcomes can be substantially lower if:
  - Compensation is cost based and such costs are significantly below bids/offers; and/or
  - Only a small part of the capacity is offered above cost;
- The timing of a CPT breach is unknown since it is ultimately driven by uncertain events, e.g., a deviation of demand from the expected demand, and/or unforeseen outages. At any given point in time, a generator may at best have a view of expected demand and information on availability of competing generators over the next few days.[34] However, it will be extremely difficult, if not impossible, to form an *a priori* estimate of compensation because it requires knowing in advance when a CPT breach might occur.
- Further, a compensation payment is not absolutely guaranteed and has less certainty compared to spot market revenue.[35] In other words, uncertainties surrounding a compensation payment will make it difficult for generators to compare alternative revenue streams from:

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33 Generators in reality may or may not undertake such an intertemporal optimisation to decide their offers. However, such an optimisation provides a rigorous basis for understanding the impact of a CPT rather than relying on an ad-hoc procedure.

34 There will be better information and hence more certainty closer to the time when a CPT breach actually occurs, e.g., there may be pre-dispatch information on the day indicating a potential breach later in the day. This will enable generators to change their offering strategy through rebidding, etc. However, this will be a point in time when the generator has essentially already made many of the decisions on their generation offer, including the key decision to stay within the CPT limit, or breach it, that we are discussing here. Put differently, we are specifically seeking here to determine any impact of changing the CPT may have on a (rolling) seven day horizon basis, and how generators may potentially target market price outcomes over the entire period.

35 We understand that the current market rules contain some provisions that enable discretion to be applied regardless of the basis (i.e., cost or bid/offer based compensation) on which compensation amounts are

- The spot market without breaching the CPT, vis-à-vis
- Spot market plus compensation payments once the CPT is breached.

- Apart from this uncertainty, there is also a fundamental difference in spot market revenues and compensation payments. Since compensation may be characterised as a “pay as bid”, as opposed to the uniform price auction followed in the NEM that sets regional spot prices before the CPT is breached, the underlying bidding strategy would be different for the two regimes. The most important distinction is that in a uniform price auction, a generator need not put as much emphasis on offering a significant part of its capacity at the market clearing price because all of its cleared generation is paid at that price regardless of who sets the price. A generator will need to offer its generation targeting (presumably) one of the two alternative revenue streams, i.e., the revenues associated with breaching the CPT versus the revenues associated with not breaching the CPT. For reasons also mentioned above, it is likely that they will opt for maximising profit without breaching the CPT.

In the short history of the NEM, there has been only one CPT breach and a few near misses. On the only occasion when the CPT was breached, there was no compensation claim. In addition to the AER’s analysis of bidding behaviour (noted below), this may support our hypothesis that generators would generally prefer to stay within the CPT rather than actively attempt to breach it to seek compensation.

A simple example may help to appreciate the points above and show why a generator may not prefer to breach the CPT. Suppose there are three generators, each with 100 MW capacity with short run marginal costs (SRMC) of $10, $50 and $350 per MWh. Expected demand is 240 MW. Regardless of the exact demand level realised, generators may be in a position to withdraw their capacity and raise prices up to VoLL or, alternatively, this same effect may arise from an outage of any of the three generators.[36]

A typical offering strategy under that circumstance would be that each generator offers a part of their capacity well above their SRMC potentially close to VoLL. For example, each generator could choose to offer 20 MW of their capacity at $1,000/MWh taking into account what their rivals might do.[37]

Generators would typically bid the rest of their capacity well below $1,000/MWh and probably at their SRMC to get dispatched. Spot price will be set at $1,000 MWh regardless of whose bid is cleared and all three generators receive this price.

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calculated. Firstly, the expert panel deciding the compensation may apply some discretion in advising the AEMC on the value of compensation to be paid. AEMC may further use discretion in determining the final value of compensation to be paid and also reserves the right to retain such discretion for any future compensation.

36 This is an extreme assumption but unusually high demand periods may lead to such situations as some of the price events in SA in March demonstrated. For example, this is apparent in the AER’s analysis of March 2008 events. Figure 2 of the AER report suggests that for levels of demand above 2,500 MW, the bidding behaviour of some larger generators may have changed.

37 That is, the offer price and volume will reflect some form of expected equilibrium outcome that is based on expected rival strategies. The offer price and volume would also depend on a range of other actors, including contractual obligations, elasticity of demand, competition from the demand side and imports. If we assume a demand curve: Spot Price = $10,000 – 40*(Total Generation), the Nash equilibrium price in this case assuming no contracting, imports, DSM, etc is $2,600/MWh, and the three generators offer between 40 to 50 MW at that price to maximise their profit. If we assume, however, that the first two generators with lower cost are heavily contracted at 80 MW and the third generator has a lower contract of 50 MW, the Nash equilibrium price decreases to $500/MWh with much less capacity being offered at high price.

A compensation payment, in contrast, does make that distinction. The cheaper generators in an APP will receive no compensation at all if their expensive bid is not cleared. Assuming an APC of $100/MWh, the expensive generator will be guaranteed to receive some compensation because it has an SRMC higher than the APC.[38] Since the generators have an expectation of the spot price and rival firms' cost structures, it is likely that during an APP, i.e., when they know CPT has been breached, they will take this information into account and bid at a price at least higher than $100/MWh, if not bid the entire capacity close to their expectation of highest marginal cost (i.e., $350/MWh) or equilibrium price (i.e., $1000/MWh), to maximise compensation.[39]

Regardless of which of these strategies they choose, it is not hard to see that generators' total net revenue from APC would diverge widely from the sum of APC plus compensation whenever the expected spot price is substantially higher than the APC, and that the associated profit maximising solutions would require them to bid differently, if not very differently.

Contractual obligations would discipline this behaviour to some extent, but if demand is sufficiently high, the majority of the generators would be prepared to accept the relatively low dispatch risk, rather than risk losing out on what may be a very substantial compensation payment. That said, compensation payments generally would be more uncertain and a generator would also need to consider this in forming a view on its *expected* compensation payment. Taking an extreme case, if all three generators decided to bid all of 100 MW around $1,000/MWh, they all face a risk of an uncertain compensation payment because only two of them may get fully dispatched, while the third generator may only supply 40 MW.[40] Compensation payments for all generators may vary between $36,000 (($1,000-$100)*40 MW) and $90,000 (($1000-$100)*100 MW = $90,000). Any variation in demand would increase this uncertainty, e.g., if actual demand turned out to be 210 MW, the lower end of compensation would be only $9,000.

In contrast, in a uniform auction setting, the generators need to withdraw a smaller quantum to ensure that a $1000/MWh settlement price is achieved for all of its cleared generation volumes.

Given the pervasive uncertainty around whether and when a CPT breach would occur, a generator with some degree of pricing discretion effectively has to choose between targeting an outcome that prevents a CPT from being triggered, as opposed to an outcome whereby the CPT is breached and the generator earns compensation. The discussion above suggest that generators are more likely to maximise profits by submitting price-quantity offers that keep prices within the CPT but do not necessarily breach it.

38 Using the current APC level of $300/MWh does not change any of the general conclusions deduced from the analysis.

39 This will be a typical outcome in a "pay as bid" or discriminatory auction and has been a well documented critique of the British electricity market reform. See for example, Catherine Wolfram, *Electricity Markets: Should the Rest of the World Adopt the UK Reforms?*, University of California Energy Institute, 1999. Wolfram, among others, has argued that a discriminatory auction would encourage generators to bid more aggressively than they would in a pool or uniform auction.

40 If all offers are identical, a tie-breaking rule in dispatch engine would prevent such an outcome. However, we assume the offers are close to $1,000 but not necessarily identical.

The limited anecdotal evidence provided by recent high price events in the NEM seems to support this view. The AER report has noted in the context of the March 2008 price event that "*At the commencement of the heatwave, the cumulative price was $10,300. Over the next three days, the spot price approaches $10,000/MWh on 13 occasions, with the cumulative price reaching $132,000 on 7 March….. for the next four days, despite demand being at or above 2,500 MW, the spot price did not exceed $400/MWh…….On 12 March, 2008, which is seven days into the high priced period, if AGL had continued the bidding behaviour of the previous four days then the cumulative price would have fallen significantly. However, the bidding strategy of AGL on 12 March saw spot prices returning to levels close to $10,000/MWh*". One might interpret these and other events in that month as reflecting a strategy to monitor the CPT, and trying to stay within it over March 9-12 rather than breaching it, which it probably could given the level of demand.

The model design therefore incorporates an explicit CPT constraint on cumulative price outcomes. Sub-section 3.3 contains further analysis, using an illustrative example, to conceptually analyse how the CPT is likely to influence generator bidding behaviour.

3.1.2. Assessment of Financial Risk for Market Participants

A measure of financial risk faced by market participants is volatility of spot prices. Volatility is driven by the combination of the behaviour of market participants (especially generators) and stressed system conditions (such as a significant departure from forecast demand, outage of generators, transmission lines, lower than normal inflow for hydro plants and gas supply interruptions). Spot price volatility creates different forms of risk for different participants, namely:

- Retailers with exposure to spot prices will face a drastic increase in the spot price. Even if they are hedged through an appropriate mix of contracts, persistently volatile spot price outcomes will also have an effect on contract prices over time, thereby increasing retailers' costs. If contract prices increase significantly, this may lead to retailers purchasing fewer contracts. On the other hand, an increase in VoLL will increase the value at risk (VaR) faced by the retailer and it may choose to buy a higher level of contract. If retailers have a significant exposure to peak period prices, it may also encourage them to build/buy peaking generation capacity to hedge their risk instead of buying (what they consider to be relatively expensive) cap contracts. Therefore, if VoLL goes up, the retailers would need to decide on purchase of additional volume of contract. This will require striking a balance between a potentially higher contract price and a higher level of risk absent such additional contracts. As Cramton and Stoft (2008) have argued, whether the contract level would change on balance in presence of an imperfect demand-side response is a difficult question.[41] Depending upon its load profile, a retailer may therefore decide on a portfolio of contracts that matches the load profile. We have accordingly:

[41] P. Cramton and S. Stoft, *Forward Reliability Markets: Less Risk, Less Market Power, More Efficiency*, Utilities Policy, September 2008, pages 194-201 (Special Issue on Capacity Mechanism in Inefficient Electricity Markets). Cramton and Stoft state that the effect of increasing the VoLL in an energy only market is "i*ncreasing market risk for consumers so that generators can make more money selling them hedges*". In order to manage the consumer risk, they may need to increase their contract purchase moderated by the price increase. They argue in favour of a reliability option approach that ensures an all round efficient outcome that manages generator bidding behaviour while ensuring investment efficiency.

  - Assumed that a significant part of the generation capacity is contracted with retailers so as to match the regional load shape. Given the difficulty to predict whether the contracting level will necessary change if VoLL is increased, we have retained the same level of contracting across all VoLL/CPT scenarios;[42] and

  - Formed spot price volatility measures for different time periods from peak to off-peak to distinguish between price risks among these periods.

- Generators will, in turn, be subject to net revenue risks if VoLL, CPT and APC are set too low. Low price caps/triggers may discourage investment in peaking plants that are most prone to such risks. If not addressed over time, such a lack of investment in capacity could threaten the reliability of power supplies. To assess net revenue risks, we have therefore used net revenue risk volatility measures differentiated by periods – most importantly, super-peak and peak periods – recognising that a peaking plant relies critically on revenue from these periods.

- Finally, a smaller number of participants such as MNSPs and IRSR unit holders will be exposed to inter-regional price difference risks. Inter-regional price differences may be volatile, reflecting variation in underlying factors in regions across an interconnector or other indirect effects. Specifically, an APC in one region may have a major impact on prices in other regions that have not breached CPT. However, under clause 3.14.2 (e) of the rules, application of an APC in another region may require adjustment to prices in adjacent regions to avoid negative settlement residue outcomes.[43]

As elaborated on below, within the modelling framework, volatility of spot prices is the sole indicator of financial risks faced by market participants.

3.2. MODEL DESIGN

The model design comprises two main components:

- A game-theoretic modelling framework that explicitly captures the profit maximising behaviour of generators, given a cumulative price threshold over a seven-day period.[44] This is used to assess the impact of any changes to the VoLL-CPT arrangement on bidding behaviour.

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42 The potential increase in contract prices may be estimated indirectly through the increase in average spot price as we have discussed later in the report. We also note that any potential overestimation of customer risk is likely to be very small because (a) the base contracting level of assumed to be high covering on average 80 to 85 per cent of demand (b) the variation in VoLL is relatively small. The analysis in Cramton and Stoft (2008) in comparison considers variation of VoLL in the range €3000 to €30,000 per MWh.

43 Intelligent Energy Systems, *Regional Settlement Prices During Administered Pricing*, Report to AEMC, May 2008.

44 A weekly timeframe is selected (rather than a longer timeframe) primarily to keep the data and computational requirements to a minimum. It nonetheless captures a sufficient number of peak and off-peak periods to understand the behaviour of prices during an extreme price event including a CPT breach.

- A dispatch optimisation model coupled with Monte Carlo simulation to calculate spot prices and simulate a range of uncertain events to assess spot price volatility.[45] Four time periods within a week are considered, namely, super-peak when prices exceed $1000/MWh, peak (7am to 11pm on working days), off-peak (all periods excluding peak) and flat (all half-hours in the week). This is used to quantify financial risks arising from price volatility.

These two models together constitute a *intertemporal game-theoretic bidding and dispatch framework* that has the following three important attributes:

1. The capability to simulate profit maximising behaviour by NEM generators, taking into account their long term contract and retail positions. Our model allows for Cournot, Bertrand and perfect competition (PC) paradigms, which enables us to compare and contrast outcomes and risks under alternative models of competition;

2. The ability to simulate a variety of random events, including outages of generators, constraints on flows on transmission interconnectors, significant swings in demand, and fuel supply failures. We have used a Monte Carlo simulation technique that embeds a Cournot/Bertrand/PC dispatch model to simulate these types of events. Dispatch is simulated for a range of uncertain demand, energy availability and outage conditions using Monte Carlo simulation. Volatility of spot prices derived from these simulated outcomes is then used to assess the financial risks faced by generators, retailers and MNSP/IRSR holders; and

3. The ability to "look ahead" and develop bidding strategies that takes into account the impacts of a sustained VoLL event, including one that may breach the CPT. The bidding optimisation allows for generators to rebid during high demand periods. An important aspect of the modelling is that generators explicitly take into account the "CPT limit" as a constraint in preparing their offer volumes and prices. This requires a "look ahead" using expected demand and strategies adopted by other generators.[46] The bidding optimisation model captures these details over a weekly timeframe to derive bids for each half-hourly period of the week. Specifically, the bidding strategy for each generator incorporates:

    a. An expected demand profile over the next 7 days (336 half-hourly periods);

    b. Potential bidding strategies employed by rival entities;

    c. Transmission constraints;

    d. Energy limits for hydro plants; and

    e. A cumulative price threshold.

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45 Four time periods within a week are considered, namely, super-peak when prices exceed $1000/MWh, peak (7 AM to 11 PM on working days), off-peak (all periods excluding peak) and flat (all half-hours in the week).

46 Demand function parameters have been calibrated using the actual demand, price and dispatch data. We have assumed a probability distribution around the actual demand, i.e., demand varies for each half-hour on either side of the actual demand. Calibration of the demand function refers to deriving a relationship between demand and prices using historical demand and price data. Further discussion on the approach to calibration is included in Appendix D.

As noted above, within the modelling framework, volatility of spot prices is the sole indicator of financial risks faced by market participants. Volatility of spot prices is captured using the Monte Carlo model to generate a set of random parameters on all of the uncertain events. These are equivalent to a plausible "history" of the event (although the actual event in reality may match none of these simulated histories). The simulation is effectively a randomised set of "what if" scenarios, given the probability distribution of the uncertain parameters.

For instance, we know that the NEM demand forecasts have generally shown a maximum +/- 5 per cent error around the actual demand level in the past and hence this information has been used to generate a set of 100 demand samples for a week (although, again, none of these samples may match the exact half-hourly profile observed in the week). Similarly, there are other drivers of price volatility including generator/interconnector outages, available energy for hydro plants and gas supply interruptions that also have uncertainties associated with them. Appendix D discusses the assumptions used to develop random samples that combine all these factors.

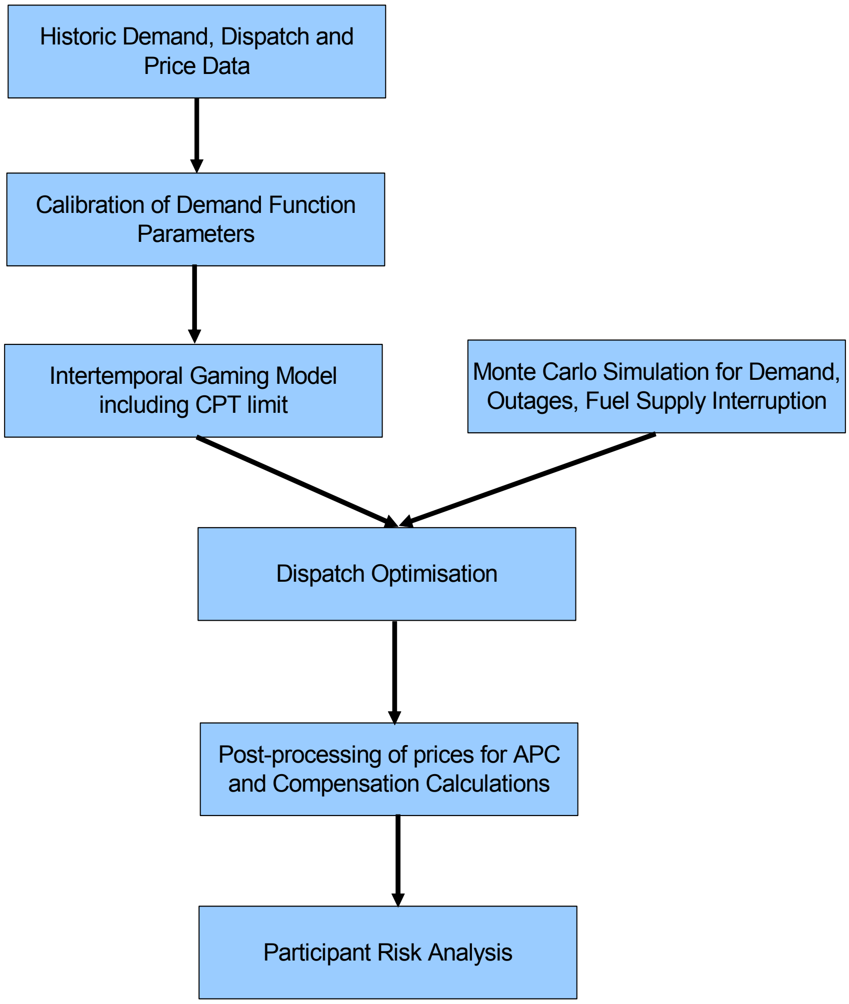
Spot prices are calculated for each of these samples. Standard deviation of cumulative and half-hourly spot prices provides a measure of spot price volatility. A high standard deviation would indicate high volatility – for instance, a mean cumulative half hourly price of $140,000 over a seven-day period with a standard deviation of say $8,000 will indicate a high risk of breaching the CPT and, in all likelihood, some of the 100 samples may well have breached the CPT.

By comparing these mean and standard deviations of the CPT for different time periods and across a range of VoLL-CPT scenarios, the model can provide insight about how this risk varies for alternative designs and what these imply for financial risks faced by different market participants.[47]

Chart 2 summarises the modelling approach we have adopted for the analysis.

47 This approach in general is representative of risk management measures adopted by electricity market participants including the NEM. Mean and standard deviation may be used to assess a range of risk indices, including Value at Risk (VaR) and profit at risk.

Chart 2 **Modelling Process**



Appendix C provides a mathematical description of the bidding model used for the analysis.

3.2.1. Limited Details and Complexity of Our Quantitative Modelling

Capturing the multitude of physical drivers that may, in conjunction with generator bidding behaviour, lead to an extreme price event is a difficult task. The difficulty arises both in terms of theoretical modelling as well as in respect of data and computational requirements. There are different theoretical postulates and alternative sets of assumptions that may trigger extreme price outcomes. Different approaches to computational implementation (e.g., probabilistic simulation versus deterministic scenarios) may potentially lead to different outcomes. Any modelling estimates are therefore, at best, indicative.

Given the limited time of less than four weeks available to undertake the analysis described in this report and a primary focus in this report on a conceptual assessment of changes to market design parameters, we have limited the volume of data and computation to the bare minimum. The focus in this report is therefore on deriving broad insights and indicative estimates of risks for key scenarios, and ensuring the transparency of assumptions and analysis, using two recent high price events, as opposed to a highly detailed analysis of every single five minute period and a large number of scenarios for several months/years.

The analysis described in this report has therefore been limited to a bidding and short term dispatch model using a linear demand function with appropriate calibration of the model parameters.[48] We do not model ancillary service markets and focus on the energy market alone. We have also limited the analysis to two high price events: the first occurring in South Australia in March 2008 and the second one occurring in NSW in June 2007.

There is a range of uncertain factors relevant to this modelling from variation of demand, uncertain hydro inflows, break-down of gas supply and outage of generators. These events are modelled using a simplified probability distribution, in some cases, relying upon very limited information. We have not modelled, for instance, the hydro river chain or gas supply network and uncertainties surrounding each physical element. Instead the impacts of these events on available energy and/or available capacity to a generator are modelled. In forming a view on the relative merits or drawbacks of various VoLL/CPT options, we have emphasised extreme scenarios such as persistently high demand, very low hydro storage and massive disruption to gas supply throughout the NEM.

Since there is limited information and time available for an exhaustive analysis, we have relied on simplifying assumptions to illustrate relevant issues, with the objective of informing the discussion on the subject rather than providing a conclusive view on these issues. We have endeavoured to make use of publicly available information to the extent available to identify potential extreme scenarios. It is envisaged that substantial amounts of further data and analysis, which are beyond the scope of this study, would be needed to fully assess these risks.

In summary, the modelling approach:

- Relies on short-term modelling only;
- Does not consider frequency control ancillary services (FCAS);
- Covers only two recent high price events; and
- Incorporates the following drivers of price volatility,
  - Generator behaviour and its interaction with the physical drivers such as:
  - Demand;
  - Hydro energy;
  - Generator and interconnector outages; and

[48] Although Cournot/Bertrand/PC paradigms are relatively abstract theoretical models, the calibration process ensures that the proposed model yields reasonably realistic outcomes.

- Gas supply interruptions.

Having summarised our modelling approach and its limitations, the following sub-section illustrates the likely impact of an increase in the CPT on generator bidding behaviour, and any subsequent impact on (peak and “non peak”) prices using a worked example.

3.3. IMPACT OF CPT ON GENERATOR BIDDING: AN ILLUSTRATIVE EXAMPLE

Table 1 presents the illustrative generator data used to show how the behaviour of a profit-maximising generator may change under a CPT. As columns 2-3 indicate, there are five companies (1-5) and six regions (1-6) in this example. It is also assumed that there is only one player in each region, which owns all the base load and peaking generation including one company that holds generation across two regions. The limited number of players implies competition in a given region is restricted to imports from other regions.

While these assumptions are extreme, the setup is useful for developing insights as to the connection between the CPT and generator bidding behaviour. As we discuss in section 3.3.2, the pricing impacts are very significant in some cases. The number of players in the NEM is far higher and hence pricing impacts in general are less pronounced. Nevertheless, we also note that extreme situations can occur under stressed conditions, such as unusually high demand, limited interconnection and generator outages. The illustrative example also helps to understand some of the extreme bidding behaviour that was observed in SA and NSW (discussed further in section 4). Short run marginal costs in the last column show highly significant variation in costs between regions and also across baseload and peaking generation.

Table 1 Generator Data Used for the Example

	Region	Company	Capacity (MW)	Availability (%)	SRMC ($/MWh)	Type
N_Gen_Base	2	1	10,000	88%	15.00	Black coal
V_Gen_Base	4	2	10,000	85%	5.00	Brown coal
S_Gen_Mid	3	3	3,000	88%	35.00	CCGT
N_Gen_Peak	2	1	1,000	86%	100.00	GT - Gas
V_Gen_Peak	4	2	2,000	86%	150.00	GT - Gas
S_Gen_Peak	3	3	1,000	86%	300.00	GT - Liquid
Q_Gen_Base	1	4	10,000	88%	12.00	Black coal
T_Gen_Base	5	5	3,000	85%	-	Hydro
SY_Gen_Base	6	3	2,000	88%	-	Hydro
Q_Gen_Peak	1	4	500	86%	200.00	GT - Gas
T_Gen_Peak	5	5	500	86%	350.00	GT - Liquid
TOTAL			43,000			

3.3.1. Assumptions used for the Illustrative Example

In this example, dispatch and price outcomes for seven periods are simulated under two scenarios – with and without a CPT limit. Inverse demand curve[49] parameters for these seven hourly periods for each region are chosen arbitrarily to have an intercept equal to VoLL and linear slope parameters ranging between 0.5 and 1.25, depending on the demand over the periods in each region.[50] This implies prices will be below $10,000/MWh. For instance, if generation in a region is 10,000 MW and the slope is 0.95, the price will be 10,000-0.95*10,000 = $500/MWh. If the slope is low, prices are high, representing peak period prices. The slope for periods 3-5 is kept relatively low to simulate high price events for these periods.

Transmission interconnection capacity among the regions is shown in Table 2. As noted in the preceding section, these capacity constraints have important implications for generators' offer strategies and may result in price separation among regions. Differences in demand characteristics among regions may also contribute to such price separation.

[49] Price is expressed as a function of demand, namely, price = α – (β . Demand). This is a downward sloping line, implying that a higher volume of electricity will be purchased at a lower price.

[50] Demand curve intercept and slope parameters for the NEM application is calibrated using the price, demand and price elasticity of demand data used for the case studies.

Table 2 **Transmission Interconnection Capacity Used for the Example (MW)**

Line	From Region	To Region	Max Forward Capacity (MW)	Max Reverse Capacity (MW)	Average Loss (%)
1	5	4	630	480	7.0%
2	2	1	180	195	5.0%
3	2	1	621	1078	4.6%
4	6	2	3465	1150	4.1%
5	4	3	220	135	3.5%
6	4	3	460	300	2.6%
7	4	6	1235	1863	4.4%

We do not assume any uncertainties in any of the input parameters in this example. That is, demand, generator, interconnection and energy availability are assumed to be deterministic. This enables us to focus solely on the change in generation strategy and prices arising from a CPT limit. In reality, outage of both generation and transmission can add substantially to prices because these events can restrict available capacity and also encourage the owners of the remaining capacity to bid aggressively. We have simulated outage events and discussed these issues in the context of the NEM simulation results in section 4.

3.3.2. Results for the Illustrative Example

We first discuss the impact of a CPT by comparing spot price outcomes with and without a CPT limit in place, and then discuss how a change in generation pattern under each of these scenarios alters price outcomes.

We have considered an example where the prices over seven periods are just above the CPT and then compare price and generation changes once the CPT is imposed. It should be noted that generators in both scenarios use a profit maximising strategy, although the CPT to an extent diminishes generators' incentives to bid aggressively in those regions that breach the CPT. We also illustrate some of the indirect impacts of CPT for other regions that do not breach the CPT, but are affected by generation prices in other regions and, hence, interconnector flow changes.

Table 3 and Table 4 show regional spot price outcomes over 7 periods with and without CPT.

Table 3 Regional Prices Without and With the CPT

Region/Period	1	2	3	4	5	6	7	Cumulative Price
				Without CPT				
1	514	514	514	1,338	1,600	514	490	5,484
2	541	541	541	1,300	1,559	541	516	5,540
3	514	514	514	993	1,145	514	543	4,738
4	488	488	488	1,046	1,206	488	516	4,721
5	464	464	464	1,101	1,269	464	490	4,716
6	514	514	514	1,368	1,641	514	543	5,609
				With CPT of $5000/MWh over 7 periods				
1	386	383	438	1,338	1,600	439	417	5,000
2	398	394	455	1,300	1,560	457	434	5,000
3	555	556	551	993	1,145	550	578	4,928
4	527	529	523	1,046	1,206	522	549	4,901
5	496	496	497	1,101	1,269	496	521	4,876
6	354	350	417	1,367	1,640	418	454	5,000

Table 4 Regional Generation Without and With the CPT

Region/Period	1	2	3	4	5	6	7	Total Generation
				Without CPT				
1	5,059	4,928	7,589	10,500	10,500	7,744	8,269	54,589
2	5,045	4,914	7,567	10,546	10,551	7,722	8,247	54,590
3	1,686	1,643	2,530	3,639	3,689	2,581	2,741	18,509
4	5,073	4,941	7,609	10,854	10,993	7,765	8,247	55,482
5	1,695	1,651	2,543	3,596	3,638	2,595	2,756	18,474
6	1,686	1,643	2,530	3,488	3,483	2,581	2,741	18,151
				With CPT of $5000/MWh over 7 periods				
1	5,128	4,996	7,650	10,500	10,500	7,805	8,333	54,911
2	5,121	4,990	7,636	10,545	10,550	7,790	8,318	54,950
3	1,679	1,635	2,520	3,639	3,689	2,571	2,731	18,465
4	5,052	4,920	7,582	10,854	10,993	7,737	8,219	55,356
5	1,689	1,689	2,534	3,596	3,638	2,586	2,747	18,479
6	1,715	1,671	2,556	3,488	3,483	2,607	2,767	18,287

The following observations can be drawn from the results of this illustrative example:

- Prices in all regions are significantly above the marginal cost of generation with and without a CPT. Prices without the CPT are significantly higher compared to the "With CPT" scenario. Marginal cost of generation is at most $350/MWh (i.e., the highest SRMC in any region). Spot prices are higher than this for all periods and considerably higher during periods of high demand. In fact, prices in region 5 in some periods for a scenario that assumes perfectly competition are zero if no peaking generation is needed, and yet prices in all regions are in several hundred dollars per MWh. This is, of course, exacerbated by the fact that there are only six players across the entire system, with a single player in each region. Nevertheless, this example highlights some important attributes of the problem that are discussed below.

- Where there is no CPT, cumulative prices exceed $5,000 in regions 1, 2 and 6. As a result, when a CPT limit is imposed in the theoretical model, we would expect some changes in generation patterns and, hence, prices. We find that this is indeed the case. Imposing a CPT limit:[51]

  - Prices during the peak periods 4-5 change very little. This is because all available generators are effectively at their profit maximising position by offering part of their capacity at very high price, well above marginal cost of generation. If an unforeseen generator/transmission outage or a surge in demand occurs, prices would likely go to VoLL under such circumstances as observed prices in the NEM also show. A CPT limit would not necessarily affect price outcomes (assuming VoLL is unchanged) for these periods, as this example shows.

    However, prices in other periods will need to be lowered, if the overall CPT limit is to be honoured. This reduces incentives for aggressive bidding behaviour by generators in those non-peak periods. Prices in regions 1, 2 and 6 exhibit these pricing effects. Prices in all non-peak periods drop and generation increases;

  - It is also useful to look at spot price risks as CPT is increased, as Chart 3 shows. Prices in region 1 increase from below $400/MWh to over $500/MWh, or by 35 per cent, for an increase in CPT from $5,000 to $5,500. If we do not assume a change in VoLL, i.e., if the peak period price does not change, an increased CPT in this case still leaves the prospect that non-peak prices may rise significantly;

- There are also indirect impacts on prices in other regions. A binding CPT limit creates both opportunities and potential drawbacks for generators in other regions, namely:

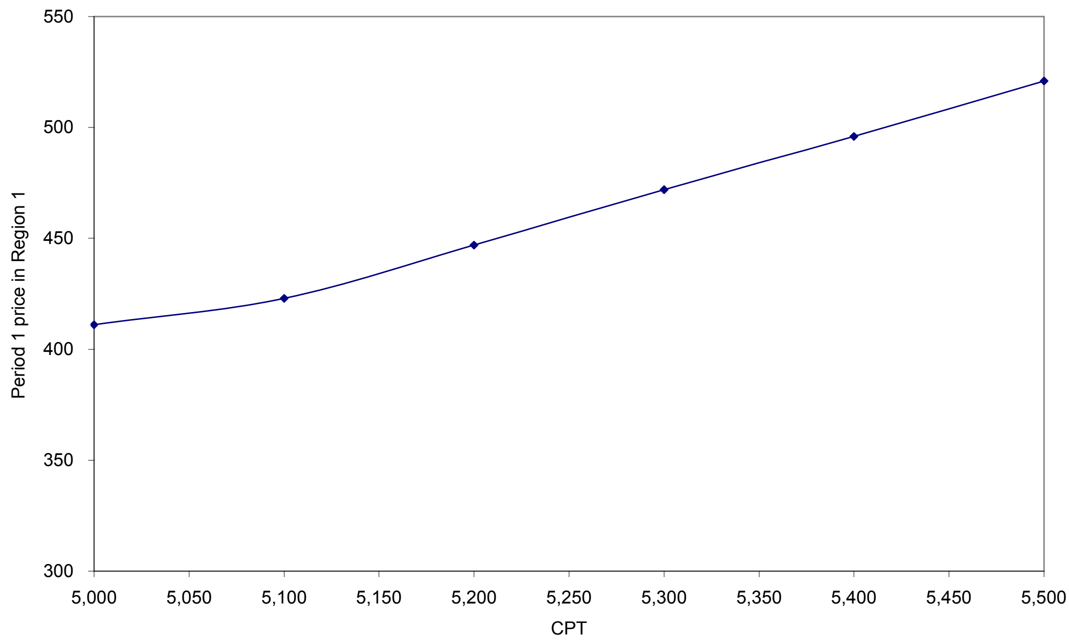
  - Some generators in other regions may benefit because the binding CPT affects behaviour of their competitors. A reduction in prices may create revenue upside for some generators who can bid higher within the bounds of the CPT.

  - In regions 3-5 in our example, prices increase to a level close to the CPT (but without breaching it). Thus, the indirect impacts may also result in regional prices coming closer overall to the CPT.

[51] Constraint 10 in the mathematical formulation in Appendix C.

- On the other hand, a higher volume of generation from regions with a binding CPT will tend to reduce the ability for other generators to bid aggressively, also prompting them to increase generation and depress prices. There are potentially extreme cases where prices may drop to SRMC level and create a significant price divergence between regions.
- A further factor that may complicate pricing impacts is the generation portfolio holdings across regions. In our example, generator 3 holds generation assets in regions 3 and 6 and therefore can trade off generation across its trans-regional generation portfolio to maximise its overall profit.

Chart 3 **Impact of CPT on Spot Price: Period 1 price for Region 1**



3.4. MARKET SCENARIOS TO ASSESS PARTICIPANT RISK

Before presenting the results of NEM analysis, we first summarise the scenarios and sensitivities used to quantitatively assess the risks faced by different market participants. For modelling purposes, the risks faced by market participants, which have been summarised in sub-section 3.1.2, are separated into the following two broad categories, namely:

- *Physical* – as driven by demand, outage of generation, transmission and fuel supply components. These categories may again be further subdivided into sources of risk that are more frequent but low impact, as compared to a fuel supply failure that is infrequent but has a high impact. We have used a set of random samples in a Monte Carlo model to assess these risks; and
- *Behavioural* – that arise from strategies in response to a higher VoLL and CPT. We have used game-theoretic models and appropriate scenarios to develop views on this source of risk.

Market price outcomes reflect a combined impact of all the factors. We have constructed a set of random samples to capture the risks associated with both physical factors (e.g. high demand, interconnector outages, generator outages and fuel supply interruptions), as well as any associated changes in generator bidding behaviour.

3.4.1. Risk Measures

As noted above, we use volatility of regional spot prices for different time periods (for example, peak, shoulder and off-peak) as a measure of risk. In developing a risk measure, we also distinguish between a short spike in price vis-à-vis a sustained increase in price over several hours.

3.4.2. Risk Assessment

Depending upon the type and exposure of market participants to spot prices, the nature and magnitude of impacts may vary considerably. For instance:

- A retailer with peaking generation may at least partially offset the impact of higher spot prices;
- Portfolio generators with peaking generator may gain substantially more, compared to baseload-only generators (although the effect would depend on their contract positions); and
- Participants exposed to inter-regional price differences may again have very different risk profiles, depending on the vulnerability of a region to an interconnector and/or peaking capacity/energy and/or gas supply outages.

For each risk scenario, we have developed illustrations for the following generic market participants, and for each region:

- Retailers;
- Generators; and
- MNSPs and IRSR holders.

Having set up the necessary scenarios, spot price profile and risk profile for generic market participants, we compare and contrast systemic risks arising under alternative VoLL/CPT scenarios and alternative market paradigms (e.g., Cournot versus perfect competition), to identify systemic risks for each class of participant and a broad measure of their likely impacts. Detailed simulation results are presented in the next section.

4. MARKET MODELLING RESULTS

This section sets out and explains the modelling results we have derived:

- First, we discuss the two recent high price events that form the basis of the market simulations;
- Second, we simulate the impact of various combinations of VoLL-CPT increases on market prices; and
- Third, based on these simulations, we assess financial risks on different market participants.

4.1. TWO REPRESENTATIVE WEEKS USED FOR THE STUDY

Simulation of the high price events in the NEM in recent years focused on two representative weeks, namely:

- March 11-17 in 2008, when SA experienced a series of high price events that led to breaching the CPT on March 17 around 5:30 pm. Demand and prices for the week used in the model are shown in Chart 4; and
- June 12-18 in 2007, when NSW among other regions experienced very high prices with cumulative prices exceeding $120,000 for the week, although the CPT was not breached. Demand and prices for the week used in the model are shown in Chart 5.

Analysis of these two weeks provides a good basis for understanding the general behaviour of prices driven by some of the key drivers. As the AER analyses show, in both instances, demand was identified as one of the key drivers of changes in spot price patterns, but there were other related factors, including generator bidding, that may have exacerbated price effects.

The SA price event in March 2008 was a relatively localised phenomenon that led to more extreme prices and was found to be primarily caused by a combination of high demand and bidding behaviour by some of the local generators. The high price event in NSW in June 2007, in comparison, was much more widespread. Prices in QLD were also high. Both NSW and QLD price excursions were caused by a combination of high demand and plant unavailability due to water restrictions. The effect of plant unavailability is reflected by a generally higher price maintained throughout the week in addition to short duration price spikes. Some generators in NSW exhibited extreme bidding behaviour that led to a significant number of the price excursions. Overall, the events in these two weeks provide a reasonable basis for analysing most of the physical and behavioural drivers.

A detailed account of key model input assumptions is provided in Appendix C.

The objectives of the simulation exercise we have carried out are to explore potential price outcomes and the nature of volatility should such high demand conditions recur, and to understand how a combination of outages, demand and energy limits may lead to such extreme price volatility. Modelling results should be interpreted carefully in this context. We specifically focus on extreme price events that may cause financial stress. These cannot and should not be generalised to a wider context. For instance, if a price increase of (say) 20 per cent is reported for a VoLL/CPT scenario, it reflects how an increase in VoLL/CPT would impact on prices under such stressed condition. This provides an objective assessment of a change in the price cap instrument settings, useful for understanding the associated risk implications against the backdrop of a real-life event.

However, such an outcome is not intended to be generalised to NEM price outcomes under all possible circumstances, much less normal conditions (i.e., average demand condition without major outages, etc). The only thing that can in fact be said with certainty is that the NEM prices in general will not in all likelihood increase by anywhere near 20 per cent for the vast majority of hours. The study is not intended to provide an average price forecast, but instead is intended to assess the efficacy of risk instruments under extreme low probability events.

Chart 4 South Australian Demand and Prices used in the Model

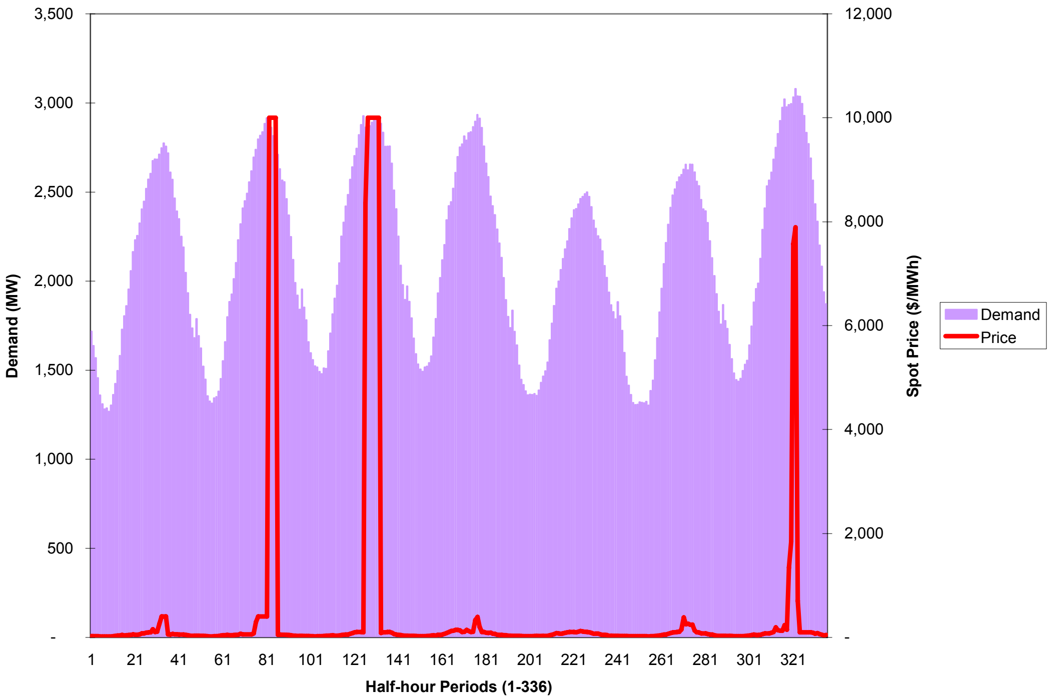
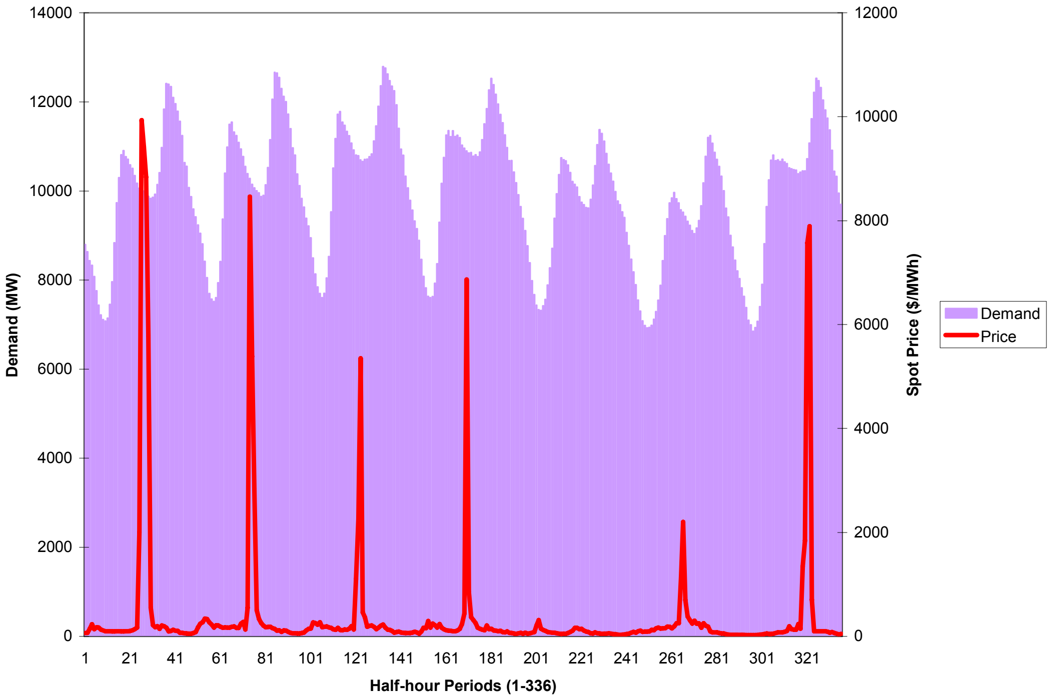


Chart 5 New South Wales Demand and Prices used in the Model



4.2. IMPACT OF VOLL-CPT CHANGES ON MARKET PRICES

To assess the impact of VOLL-CPT changes on market prices, we must first simulate price outcomes under the base case.

Chart 6 shows actual and simulated prices for SA for March 11-17, 2008. Simulated prices generally matched the actual prices well, suggesting that the bidding and dispatch models are reasonably well calibrated against market outcomes. The plot shows actual prices (in red) and simulated prices (below $100/MWh) for all half-hourly periods 1-336. The model reliably reproduced the (non-peak) prices, as reflected in the fact that they align reasonably well with the actual simulated prices, including the timing of peaks and troughs of cyclical nature of observed prices over the week. Price spikes were also captured well, for instance:

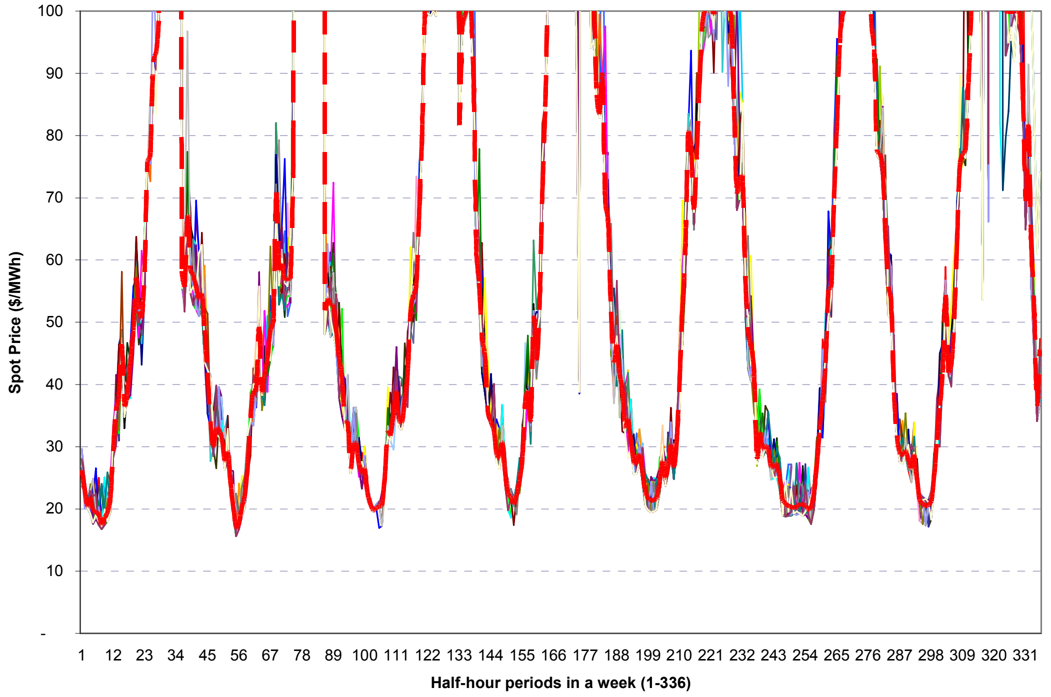
1. Half-hourly Periods 76-81: actual price averaged to $383 over these half-hour periods compared to a simulated price average of $374;
2. Half-hourly Periods 82-84: actual price reached VoLL and simulated prices were near VoLL, at an average of $8,617 over these periods; and
3. Half-hourly Periods 134-140: actual price and simulated prices were both above $9,000.

Relatively minor differences between simulated average and actual prices demonstrate the uncertain nature of prices, driven by a range of factors discussed in section D.3 and also modelling/data inaccuracies. For instance, prices did not always reproduce a VoLL event in every single sample, because some samples included lower than actual demand and/or higher than available energy. As a result, a coincidence of high demand, low availability of hydro energy, outages, in combination with generator bidding behaviour, did not cause extreme price spikes in all cases.

Mean cumulative prices in SA for March 2008 and in NSW for June 2007 are much higher than in other regions for all VoLL-CPT scenarios. However, these do not necessarily match the actual cumulative price – and do not even necessarily breach CPT for SA – because we have simulated conditions that are, in some cases, less severe than those that prevailed in reality. We have, for instance, allowed for demand to be up to 5 per cent lower and hydro energy up to 10 per cent higher than was actually the case. In addition, high price events, especially a sequence of high price events that breach or come close to breaching CPT, often occur as a consequence of more than one factor coinciding. This does not always occur in all of our randomised samples. As a result, simulated prices are close to actual prices, but inevitably show a significant standard deviation, which represents the risk of breaching the CPT. For instance, although the CPT was not breached in NSW in June 2007 , a mean cumulative price over $130,000-$140,000 on average and a standard deviation over $9,000-$10,000 shows that the probability of cumulative prices exceeding $150,000 is more than 30 percent. We discuss the risk of breaching CPT in more detail below.

Indeed, such variations are entirely plausible and form the essence of price volatility in the NEM. Market prices in June 2006 and March 2007 were much lower than those in June 2007 and March 2008, respectively. We therefore examine, not only mean outcomes, but also a standard deviation of prices as a measure of spot price volatility.

Chart 6 **Simulated Prices for South Australia for March 11-17, 2008**



Notes: The red dotted line represents actual prices. Simulated prices are shown for the base case VoLL of $10,000 and CPT of $150,000.

Table 5 presents a summary of spot prices for both the March 2008 and the June 2007 events, for both the base case and the other three scenarios in which VoLL and/or CPT are increased. The table shows mean spot price across the Monte Carlo random samples and also the standard deviation of cumulative prices.[52]

[52] Standard deviation of cumulative price across the samples shows volatility of prices. Cumulative prices vary across the samples, representing aggregate price volatility for the entire week. This should not be compared with volatility of half-hourly prices, which will generally be much lower.

Table 5 Comparison of Simulated Regional Prices* across VoLL-CPT Scenarios

CPT scenario		VoLL 10,000 (Base) Cumulative Price ($/MWh)	VoLL 10,000 (Base) Std Dev ($/MWh)	VoLL 12,500 Cumulative Price ($/MWh)	VoLL 12,500 Std Dev ($/MWh)
March 2008 Event					
CPT 150,000 (Base)	NSW	21,907	2,546	23,224	3,098
	QLD	16,126	181	17,240	190
	SA**	**142,539**	**2,532**	**143,834**	**1,437**
	VIC	49,419	6,575	51,291	8,466
	TAS	18,165	599	18,508	628
CPT 187,500	NSW	23,107	2,598	24,563	3,170
	QLD	17,219	190	18,396	209
	SA**	**153,302**	**3,459**	**171,133**	**3,333**
	VIC	51,759	6,788	56,651	8,179
	TAS	18,653	679	19,185	767
June 2007 Event					
CPT 150,000	**NSW****	**120,013**	**8,310**	**133,793**	**9,272**
	QLD	72,847	1,491	80,317	2,071
	SA	27,231	184	28,383	184
	VIC	75,490	5,321	81,698	6,081
	TAS	26,949	3,396	28,592	4,184
CPT 187,500	**NSW****	**126,872**	**8,384**	**143,536**	**10,447**
	QLD	80,356	1,660	88,044	1,874
	SA	28,383	184	29,822	213
	VIC	80,288	5,412	87,347	6,483
	TAS	28592	4184	30,377	4,892

Notes:

* Prices are capped at APC for a region that has breached the CPT and other regional prices may also be affected because prices are scaled back to avoid negative settlement residues.

** High cumulative prices for SA in March 2008 and in NSW for June 2007 are highlighted because these breached or nearly breached CPT in these months.

Net operating revenue ("net revenue"), defined as the difference between spot price and the direct operating costs, earned by generators during these extreme price events is, as expected, very high. According to recent estimates, a green-field open cycle gas turbine (OCGT) has an annual capital requirement of $63,000/MW/year. [53] We compare the net revenue earned by a typical peaking generator in SA/NSW against the annual capital requirement for the base case:

- In SA over March 11-17, 2008, a peaking generator running on gas with a direct operating cost of $60-65 per MWh runs for approximately 35 per cent of the time and earns on average $61,000/MW, or 97 per cent of the annual capital requirement. If the generator runs on oil at a direct operating cost of $355/MWh, the net revenue drops to $56,000/MW, or 89 per cent of the annual capital requirement;[54] and

[53] ACIL Tasman estimate for 2007/08, assuming a real pre-tax WACC of 9.20 per cent, a capital cost for new open cycle gas turbine of $720/kW (in 2007/08) and a fixed O&M cost of $7,500/MW/year.

[54] A peaking OCGT running on natural gas has an estimated direct operating cost of $60-65 per MWh according to ACIL Tasman report. Direct operating costs for oil-based generation is estimated at $355/MWh.

- In NSW over June 12-18, 2007, a peaking generator would earn $51,000/MW (or 81 per cent) and $41,000/MW (or 66 per cent) running on gas and oil, respectively.

Although the peaking generator in both cases recovers at least two-third of the annual fixed costs, the net revenue falls well short of the 150 per cent of the annual capital requirement that was part of the original objective of the Panel/ACCC in setting the CPT. There has been in fact a global trend in rising capital costs over the last few years that would suggest a higher CPT in absolute terms than the Panel/ACCC had put in place in 1999/2000.

The present study does **not** quantitatively assess the future system reliability impacts. Nevertheless, the fact that peaking generators do not earn sufficient net revenue to cover their annual capital requirement suggests a continuation of the base case VoLL/CPT settings may potentially lead to inadequate level of peaking investment to sustain NEM reliability standard. This seems consistent with the Panel's finding in the *Comprehensive Reliability Review:* "*….the analysis of future projections demonstrates that the USE reliability standard would be breached in the medium term at a level of VoLL of $10,000/MWh nominal*."[55] This investment risk is an important consideration that needs to be balanced with the price risk faced by retailers – an issue that is central to our analysis presented in the remainder of this report.

The following subsections comment further on the model results for the three scenarios in which VoLL and/or CPT are increased. In doing so, they provide valuable insights into the nature of risks that market participants face as a result of a change in these parameters.

4.2.1. VoLL Remains at $10,000/MWh, but CPT is increased to $187,000

If we assume a CPT limit has no impact whatsoever on generator bidding behaviour, prices should not really change if CPT is increased (say from $150,000 to $187,500 keeping the VoLL at $10,000/MWh). This is because in our experiments, we have controlled all other variations by giving all scenarios an identical set of random parameters, i.e., the nature of uncertainty does not vary across the VoLL-CPT scenarios. The simulation results suggest that, all other things being equal, relaxing the CPT limit leads to higher prices. More specifically, the simulation results confirm that increasing the CPT to $187,500, *keeping VoLL constant*, will likely lead to higher overall prices.

55 CRR, p.xiv.

This price increase is most prominent for SA in March 2008 and for NSW in June 2007, because the CPT limit is “binding” for these regions. Even if generators knew in advance the prospect of a high temperature for several hours and any outage for competitor generators (or reduced line availability), any incentives to bid aggressively would be by tempered by offsetting incentives to avoid breaching the CPT. If the CPT is raised, it effectively relaxes a constraint and this leads to an increase in the cumulative price for SA by more than $10,000 or, put differently, adds $30/MWh to average half-hourly prices for the week (i.e., an increase of approximately 7 per cent). Electricity purchase costs at spot prices for the SA market are about $11 million higher for approximately 360 GWh of energy consumed in the week. Similarly, NSW cumulative prices rise by nearly $7,000 or $18/MWh on average (approximately 6 per cent). Although this is lower than SA in relative terms, electricity purchase costs for NSW retailers for the week are $30 million higher for the 1,674 GWh energy consumed in NSW in the week. There is a flow-on impact on other regional prices too, albeit generally smaller.

4.2.2. VoLL is Increased to $12,500/MWh, but CPT is Retained at $150,000

An increase in VoLL keeping the CPT constant may increase prices as a result of a combination of physical drivers and generator bidding behaviour. If, for instance, the system has a capacity constraint, an increase in VoLL will increase prices for those periods, but generator bidding behaviour is likely to exacerbate these price effects. However, a binding CPT/APC limit will, to some extent, curb the impact of generator bidding behaviour. The simulation result shows SA prices do not increase significantly. This is to be expected, because prices were already close to the CPT and an increase in VoLL (without increasing the CPT) triggers administered prices more frequently and earlier in the week. As a result, cumulative prices do not increase significantly.

To the extent a lower CPT of $150,000 prevents prices from signalling capacity shortages, the CPT will have the effect of deterring efficient investment, especially in peaking capacity A CPT of $150,000 is still sufficiently higher than the annual capital requirement of $63,000/MW/year, allowing the OCGT to earn a reasonable return. [56]

When the regional generation and import capacity falls short of meeting demand, prices increase to the (higher) VoLL. Prices also increase in general because a higher level of VoLL would generally lead to a more aggressive bidding behaviour by the generators. [57] In June 2007, NSW cumulative prices were, for the majority of the week, significantly below the CPT. The CPT limit was therefore less binding, and this would present a greater opportunity for some NSW generators to bid aggressively. However, there was also less overall energy available due to water restrictions, and a higher VoLL led to higher prices, in addition to more aggressive bidding.

Compared to the base case simulation, increasing VoLL to $12,500/MWh, but retaining CPT $150,000, leads to an increase in average half-hourly prices in NSW for the June 12-18, 2007 week of over $40/MWh, leading to an additional spot price purchase cost of $69 million.

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[56] In the present case, an OCGT (in SA) would operate for 40 per cent of the periods and would earn a net operating revenue of over $65,000 for the week.

[57] A higher VoLL may encourage a generator to bid aggressively during peak periods (or more generally reallocate more MW to higher priced offer tranches) to maximise profit, although this would depend also on other factors, including the relative cost of competitors and the presence of transmission constraints.

4.2.3. Both VoLL and CPT are Increased

As the preceding two points imply, an increase in both VoLL and CPT may potentially expose market prices to both forms of risk, namely:

- Physical risks, leading to shortfall events, would incur a higher VoLL price; while
- Generators, facing a lower risk of a binding CPT, are able to bid more aggressively.

The simulation results suggest that the market could have experienced significantly higher prices if VoLL were set at $12,500/MWh and CPT were set at $187,500. In these circumstances, on average, prices increase by $85/MWh – i.e. by 20 per cent – compared to the base case. SA retailers face a spot market purchase cost increase of $27 million, a much greater increase than the scenario when only VoLL is increased. This is unsurprising, because, when only VoLL is increased, the CPT-APC provides a constraint on prices. In contrast, relaxing the CPT provides greater opportunity for aggressive bidding by generators .

This last point becomes clearer if we look at the difference in spot prices between the high VoLL-CPT scenario and the base case.

Chart 7 shows that a number of “non-peak” (primarily shoulder period) prices were higher due to aggressive bidding from generators throughout the week. This explains the significant increase in cumulative price in the high VoLL-CPT scenario.[58] Peak prices also increase by $1,600-$2,100, as Chart 8 shows. The increase in peak prices are driven by the gap between the higher VoLL of $12,500 and the base VoLL of $10,000 (i.e., the increase is in the same order as: $12,500/MWh less $10,000/MWh or $2,500/MWh). The increase in peak prices reflects a genuine scarcity in supply. Similarly, NSW prices in June 2007 would have been $70/MWh, or 20 per cent, higher for the week and would have cost retailers an additional $117 million in spot market purchase costs. In absolute dollar terms, these price increases are significant.

Pricing impacts in other regions are generally smaller but are significant in some cases:

- In March 11-17, 2008:
  - NEM prices excluding SA would increase by approximately $10/MWh relative to the base case (compared to a $85/MWh increase in SA);
  - VIC prices increase significantly by $21.5/MWh. Cumulative VIC prices in March 11-17, 2008 were also high, around $50,000, driven by high demand in the region and to a large extent reflecting high prices in SA. An increase in VoLL-CPT would increase prices to over $56,000 for the week and also increase the volatility from $6,575/MWh in the base case to $8,179. While these prices do not risk breaching the CPT, an increase in prices would affect wholesale energy purchasers.
- In June 12-18, 2007:

58 These pricing effects are analogous to the inter-temporal bidding issues that we have discussed and illustrated elsewhere. As we had noted, a binding CPT limit will affect non-peak prices to maximise overall profit.

- NEM prices excluding NSW rise by $25/MWh relative to the base case compared to a $70/MWh increase in NSW. As we discussed before, the June 2007 event was more widespread and high prices were observed in other states too;
- In particular, QLD prices averaged over $200/MWh for the week. An increase in VoLL-CPT would further increase it by $45/MWh or an increase cumulative price level of $15,000 for the week.

Chart 7 South Australia Prices: Difference in Half-hourly Prices (< $100/MWh) for Scenarios {VoLL=12,500, CPT=187,500} versus {VoLL=10,000, CPT=150,000}

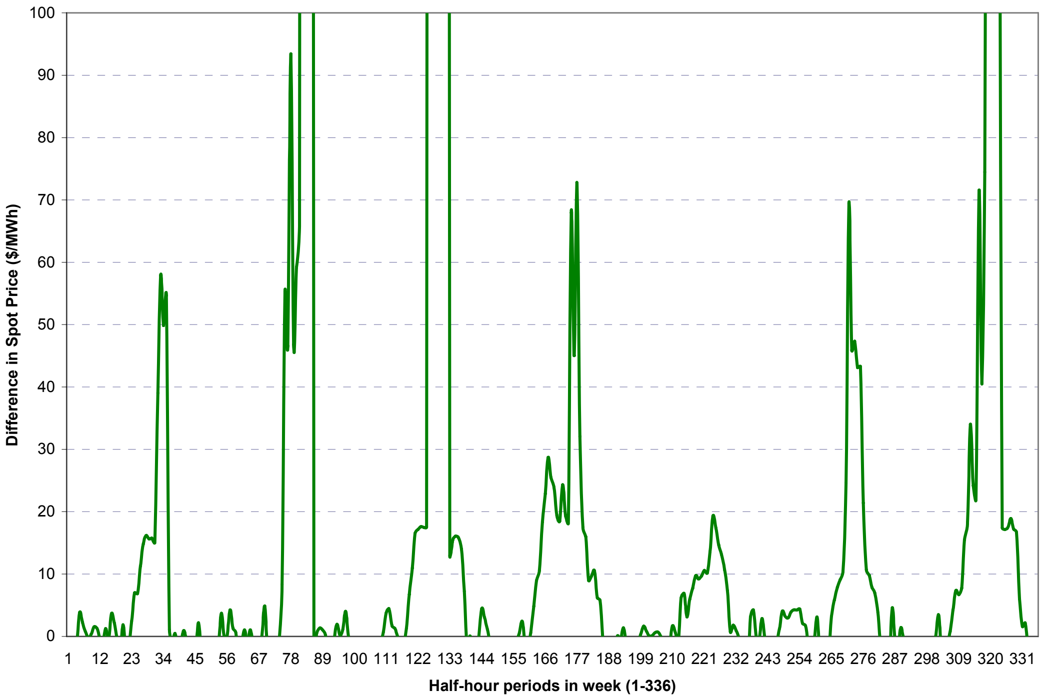
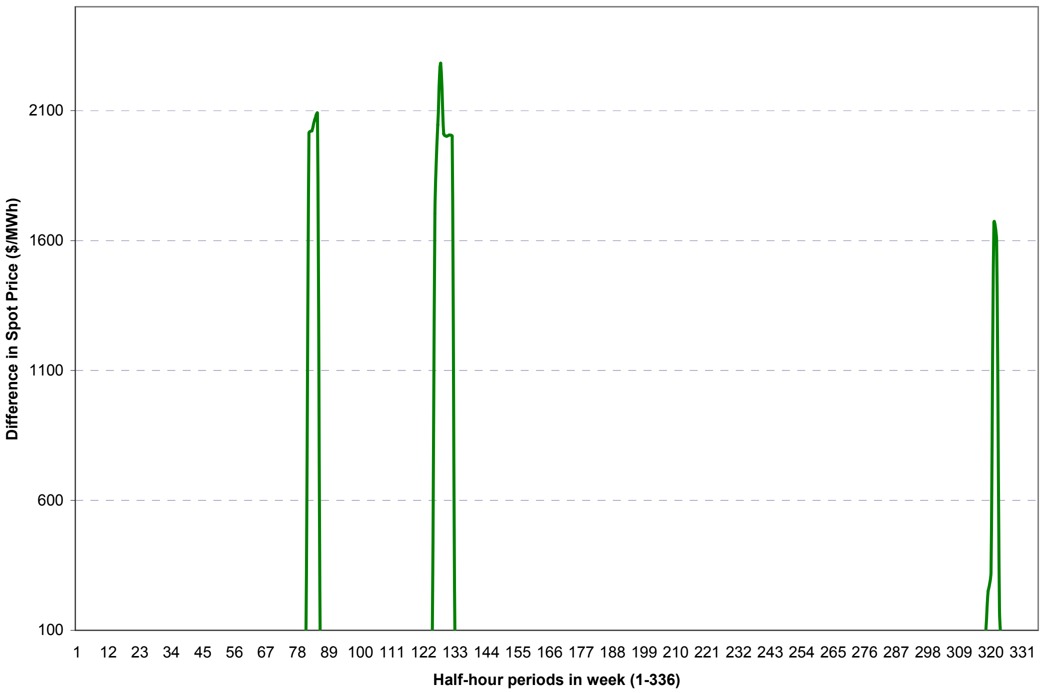


Chart 8 South Australia Prices: Difference in Half-hourly Prices (> $100/MWh) for Scenarios {VoLL=12,500, CPT=187,500} versus {VoLL=10,000, CPT=150,000}



4.2.4. Risk of Breaching the CPT

Finally, we provide some statistics on the risk of breaching CPT for different combinations of VoLL and CPT. Table 6 shows the probability of getting within 5 per cent of the CPT – i.e., where there is a very high risk of breaching the CPT. We have ignored the combination of VoLL $10,000 and CPT of $187,500 because, under this combination, there is practically no risk of breaching the CPT for either SA or NSW in our case studies. Also, in order to understand the inherent risk of exceeding the CPT, we have not post-processed prices to replace actual market prices with the APC.[59]

Our simulation results show SA had a 29 per cent for the base case – in other words, a fairly high risk of breaching the CPT. (Of course, in reality, it had breached the CPT.) Increasing the VoLL to $12,500 will almost certainly breach the CPT for this case. However, if the CPT is also raised to $187,500, the risk is lowered by an order of magnitude to 9 per cent. Similarly, NSW prices in June 2007 were well below the CPT. Thus, they have a zero risk of breaching the CPT in the base case. An increase in VoLL alone leads to a significant risk (24 per cent) of breaching the CPT. A commensurate increase in CPT raises prices, but renders the CPT high enough to lower the risk of breaching the higher CPT back to zero.

Table 6 Probability of Cumulative Price Exceeding 95 Percent of CPT

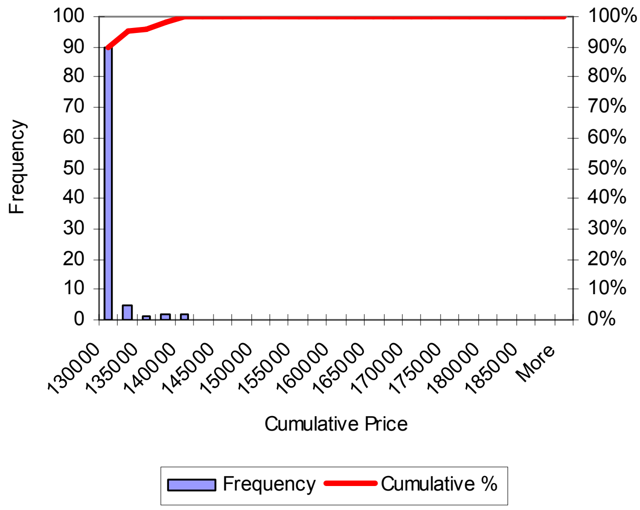
	SA in March 2008	NSW in June 2007
VoLL=$10,000; CPT=$150,000	29%	0%
VoLL=$12,500; CPT=$150,000	99%	24%
VoLL=$12,500; CPT=$187,500	9%	0%

Note: Probabilities are calculated as the number of samples that have cumulative price over 95 per cent of the CPT divided by the total number of samples. The scenario where VoLL=$10,000 and CPT=$187,500 is ignored because it has a negligible risk of breaching the CPT.

In addition to the probability values, it is also useful to look at the frequency distribution of price events, as this provides greater insight as to how the number of high price events changes across the scenarios. Chart 9, for instance, shows the frequency distribution for the three VoLL-CPT scenarios discussed above. A frequency distribution shows how many (out of 100) samples have cumulative price in a certain range. The “Cumulative %” on the plot shows the share of total samples that have a cumulative price below a certain level. It is interesting to note how the number of low price samples (with a cumulative price at or below $130,000) reduces drastically as VoLL and/or CPT is increased. While a higher CPT reduces the risk of the CPT being breached, it also leads to a significant increase in high price events.

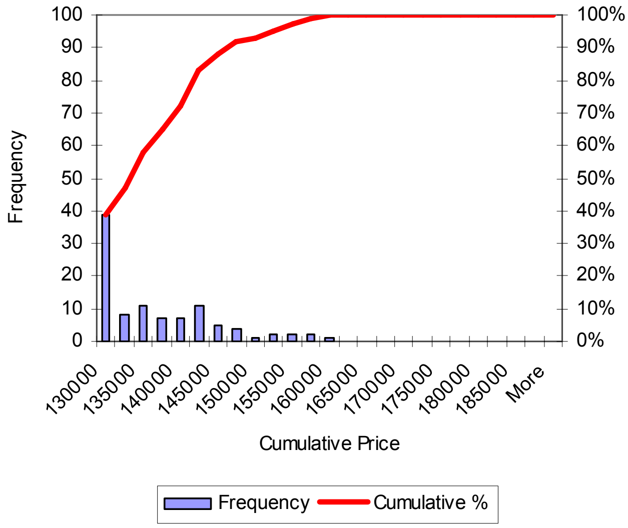
59 We consider the CPT limit in our bidding analysis. Cumulative prices may, however, go above the threshold. We have not replaced market prices following a CPT breach with the APC (or scaled APC). This effectively isolates the impact of the APC and is useful for understanding the actual behaviour of market prices and the risk of these exceeding the CPT. Applying the APC will lower prices and the risk faced by retailers – most notably, for SA with a VoLL of $12,500 and CPT of $150,000, as we have previously discussed.

Chart 9 **Frequency Distributions of Price Events for NSW in June 2007**



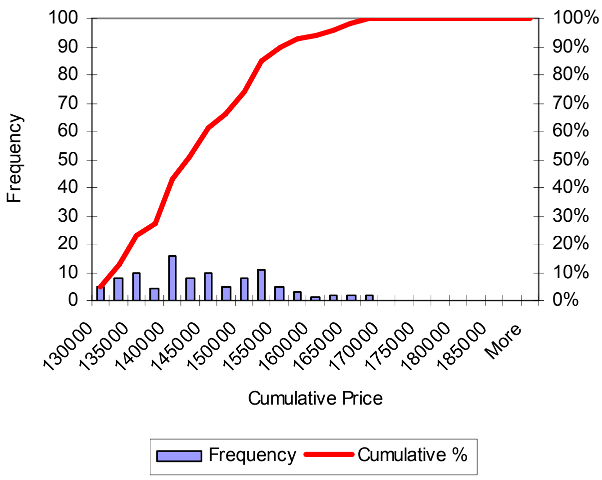
VoLL=10,000 and CPT=150,000

Nearly 90 per cent of the samples have cumulative prices at or below $130,000. CPT is not breached.



VoLL=12,500 and CPT=150,000

Only 40 samples have cumulative prices at or below $130,000. There is a reasonable chance of breaching the CPT, as several samples show cumulative prices close to or above $150,000



VoLL=12,500 and CPT=187,500

Less than 10 samples have cumulative prices at or below $130,000. Although there is no sample with a cumulative price above CPT, the change in VoLL and CPT leads to a significant increase in high price events.

4.2.5. Summary of VoLL-CPT Changes on Market Price Outcomes

Based on experiments we have conducted, using two recent high price events in SA (in March 2008) and NSW (in June 2007), our key findings are as follows:

- The hypothesis that CPT changes behaviour has been confirmed. Prices derived using market simulations confirm our theoretical assessment that, in the presence of a potentially binding CPT limit, generators would alter their bidding behaviour in all periods, and this would have indirect impacts on other regional prices;
- Changing both VoLL and the CPT results in higher prices in both peak (i.e. high demand) and off peak (i.e. low demand) periods. Prices in both periods have greater volatility. This finding has potentially serious implications for raising the CPT, which, together with an increase in VoLL, leads to a 20 per cent increase in cumulative prices overall. If CPT is increased to $187,500, prices not only increase during peak periods, but also during "non peak" periods, and the overall effect is for prices to rise reasonably close to the higher CPT;
- Raising VoLL to $12,500/MWh, but retaining the CPT at $150,000 has a minimal impact on generator earnings, but the reduction in price volatility compared to a $187,500 CPT significantly reduces the financial risks faced by retailers. Thus, SA prices will increase by less than 1 per cent. Depending upon the compensation arrangements (i.e., provided such arrangements do not unduly increase the risk faced by retailers), a CPT of $150,000 would have been effective in curbing the spot price volatility leading up to the APP;
- The combined impact of increasing both VoLL and CPT translates into an increase in total spot market purchase costs of $27 million in SA over March 11-17 in 2008 and $117 million in NSW over June 12-17, 2007. Since prices and purchase costs were already very high for these two weeks, the additional spot purchase costs may add significantly to the burden for retailers depending on the risk management strategy they have in place;
- For both NSW and SA, an increase in VoLL significantly increases the risk of breaching the current level of CPT. An increase in CPT to $187,500 drastically reduces the risk and restores it to a level comparable to that in the base case. However, an increased VoLL/CPT materially alters the distribution of prices and results in a significant increase in the number of high price events compared to the base case, as the preceding observations also suggest.

We next assess how these changes in prices impact on different classes of market participants.

4.3. ASSESSMENT OF FINANCIAL RISKS

Before we discuss the financial risks faced by different classes of market participants, it is useful to understand the distribution of prices in different pricing periods. Table 7 shows that the March 2008 event primarily affected SA, with 4.5 per cent of the week (or, 7.5 hours) experiencing prices over $1000/MWh, and, to a lesser extent, VIC. The June 2007 event affected NSW peak prices, also by 4.5 per cent, but QLD and VIC prices also stayed above $1000/MWh for 4.5 hours during the week.

Table 7 Percentage of Half-hours in Different Periods

	March 2008 Event				June 2007 Event			
	Super Peak (SP)	Peak (P)	Off-Peak (O)	Flat (F)	Super Peak (SP)	Peak (P)	Off-Peak (O)	Flat (F)
NSW	0.6	47.6	52.4	100.0	**4.5**	47.6	52.4	100.0
QLD		47.6	52.4	100.0	2.7	47.6	52.4	100.0
SA	**4.5**	47.6	52.4	100.0	0.3	47.6	52.4	100.0
VIC	1.2	47.6	52.4	100.0	2.7	47.6	52.4	100.0
TAS		47.6	52.4	100.0	0.6	47.6	52.4	100.0

Note: "Super peak" (SP) is defined as half-hour periods when price exceeded $1000/MWh. "Peak" (P) is 7 AM to 11 PM on working days. "Off-peak" (O) are all non-peak half-hours. "Flat" (F) covers all 336 half-hours in the week. Actual prices for the week are used to define the super peak period.

With this in mind, the following sub-section assesses financial risks faced by retailers, generators and MNSP/IRSR, respectively.

4.3.1. Retailer risks – Spot Price Risks

Table 8 and Table 9 show the distribution of spot prices for different time periods for all four scenarios. These provide a better understanding of what the VoLL-CPT changes imply for a retailer (or direct customers) exposed to spot price variations. In general, as VoLL and/or CPT are increased, peak and super-peak prices increase significantly, along with overall prices.

In absolute terms, the super peak price increase is more than $1,000/MWh for both SA (in March 2008) and NSW (in June 2007) if VoLL and CPT are both increased. Since super peak represents 7.5 hours in both cases, the increase in super peak price over the week is equivalent to an additional VoLL price event lasting for nearly an hour. For example, super peak price in SA (in March 2008) increases from $7,750/MWh to $9,489/MWh or by $1,739/MWh for 7.5 hours, which is equivalent to a VoLL event lasting for approximately 80 minutes, increasing the cost of a 1 MW load by $13,000 over that duration.

Standard deviation of prices also increases if both VoLL and CPT are increased. Although this is a second order issue, it does suggest that prices are not only higher on average, but are also more volatile. Therefore, additional costs in extreme cases may be substantially higher.

Prices in other regions also increase, most notably for VIC in March 2008 and QLD in June 2007. Super peak prices in these two regions increase by nearly $1,000/MWh if both CPT and VoLL are increased. These pricing effects illustrate some of the indirect impacts of raising the CPT that we have discussed in sub-section 3.2. The fact that prices were high and volatile in these regions in the base case also enable generators to bid aggressively upon raising VoLL/CPT. That said, super peak prices in VIC do not increase significantly if only VoLL is increased to $12,500. This is largely due to a price adjustment in APP because CPT is breached in SA. As VoLL is raised to $12,500 (keeping CPT at $150,000), the CPT in SA is breached and VIC prices are scaled back for several periods that would otherwise have been substantially higher than the APC of $100/MWh.

The relative increase in the mean price for SA and NSW with respect to the base case (i.e., VoLL and CPT at current levels of $10,000 and $150,000, respectively) is shown in Chart 10 and Chart 11. Super peak and peak prices for SA (in March 2008) and NSW (in June 2007) increase by approximately 20 per cent when both VoLL and CPT are increased. Increasing VoLL or CPT alone does not lead to as significant a rise in super peak and peak prices. Off-peak prices may in fact fall if the CPT is binding and generators have a much greater incentive to preserve the peak price, in an attempt to maintain overall prices within the bounds of CPT. This explains a significant drop in off-peak prices in SA in March 2008 when VoLL is increased to $12,500 but the CPT is retained at $150,000.

Table 8 Spot Price Risk Faced by Retailers: March 2008 Event in SA

		VoLL $10,000								VoLL $12,500							
		Mean				Standard Deviation				Mean				Standard Deviation			
		SP	P	O	F	SP	P	O	F	SP	P	O	F	SP	P	O	F
CPT 150,000	NSW	1,536	73	58	65	908	12	10	8	1,653	78	61	69	1,035	15	12	9
	QLD		61	36	48		1	1	1		66	38	51		0	1	1
	SA	**7,750**	**672**	**199**	**424**	**105**	**12**	**11**	**8**	**7,910**	**743**	**142**	**428**	**221**	**16**	**16**	**4**
	VIC	5,860	100	190	147	638	38	19	20	5,905	108	194	153	1,343	45	31	25
	TAS		60	48	54		2	2	2		61	49	55		2	2	2
CPT 187,500	NSW	1,631	78	61	69	925	12	10	8	1,754	83	64	73	1,086	15	12	9
	QLD		66	38	51		0	1	1		70	41	55		0	1	1
	SA	**8,396**	**730**	**207**	**456**	**36**	**12**	**13**	**10**	**9,489**	**820**	**227**	**509**	**138**	**15**	**14**	**10**
	VIC	6,144	104	199	154	513	39	20	20	6,813	114	218	169	824	47	24	24
	TAS		62	50	56		2	2	2		64	51	57		2	3	2

Note: Mean and standard deviations are calculated across all half-hourly periods to keep these comparable to the CPT, which is also a sum of half-hourly prices over a 7-day period.

Chart 10 Relative Change in Prices with respect to Base Case: SA in March 2008

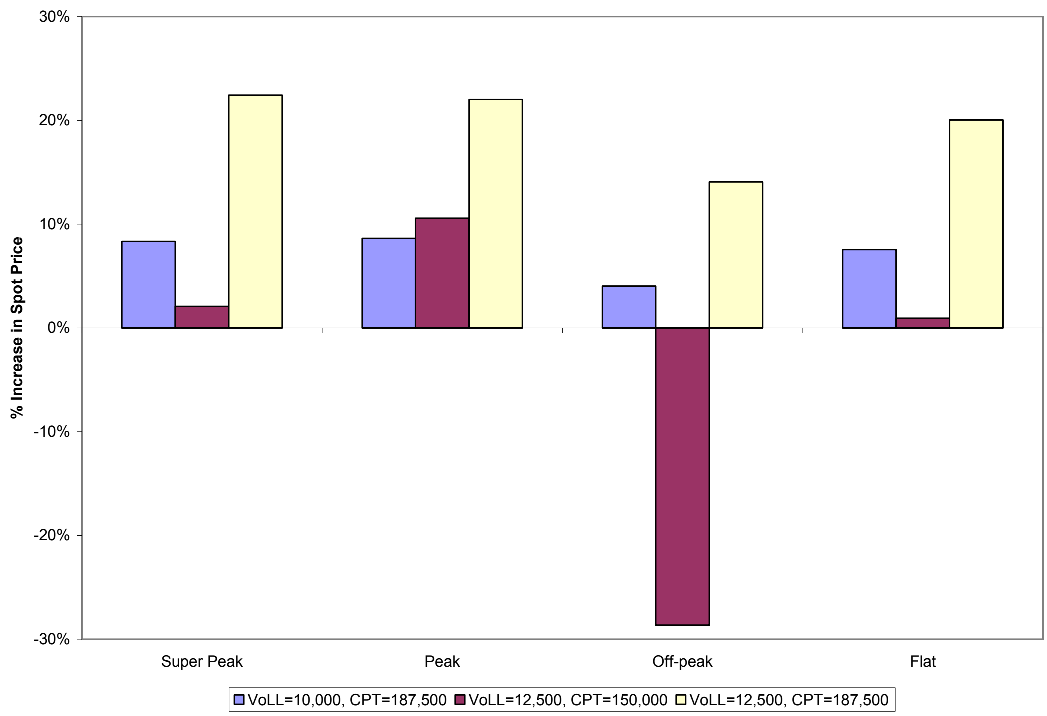


Table 9 Spot Price Risk Faced by Retailers: June 2007 Event in NSW

		VoLL $10,000								VoLL $12,500							
		Mean				Standard Deviation				Mean				Standard Deviation			
		SP	P	O	F	SP	P	O	F	SP	P	O	F	SP	P	O	F
CPT 150,000	**NSW**	**5,351**	**655**	**86**	**357**	**343**	**53**	**8**	**25**	**5,984**	**732**	**95**	**398**	**446**	**59**	**9**	**28**
	QLD	4,619	370	78	217	167	6	7	4	5,067	408	86	239	211	9	8	6
	SA	823	104	60	81	100	1	0	1	947	110	62	84	126	1	0	1
	VIC	4,541	396	69	225	587	34	5	16	4,923	429	74	243	671	38	6	18
	TAS	183	92	69	80	51	11	10	10	187	98	73	85	55	13	12	12
CPT 187,500	**NSW**	**5,590**	**688**	**95**	**378**	**348**	**54**	**9**	**25**	**6,360**	**782**	**105**	**427**	**442**	**67**	**10**	**31**
	QLD	5,061	408	86	239	186	7	8	5	5,516	447	94	262	213	7	9	6
	SA	947	110	62	84	126	1	0	1	1,132	116	64	89	164	1	0	1
	VIC	4,766	420	74	239	596	34	6	16	5,219	458	80	260	713	41	6	19
	TAS	187	98	73	85	55	13	12	12	191	104	78	90	58	15	14	15

Note: Mean and standard deviations are calculated across all half-hourly periods to keep these comparable to the CPT, which is also a sum of half-hourly prices over a 7-day period.

Chart 11 Relative Change in Prices with respect to Base Case: NSW in June 2007

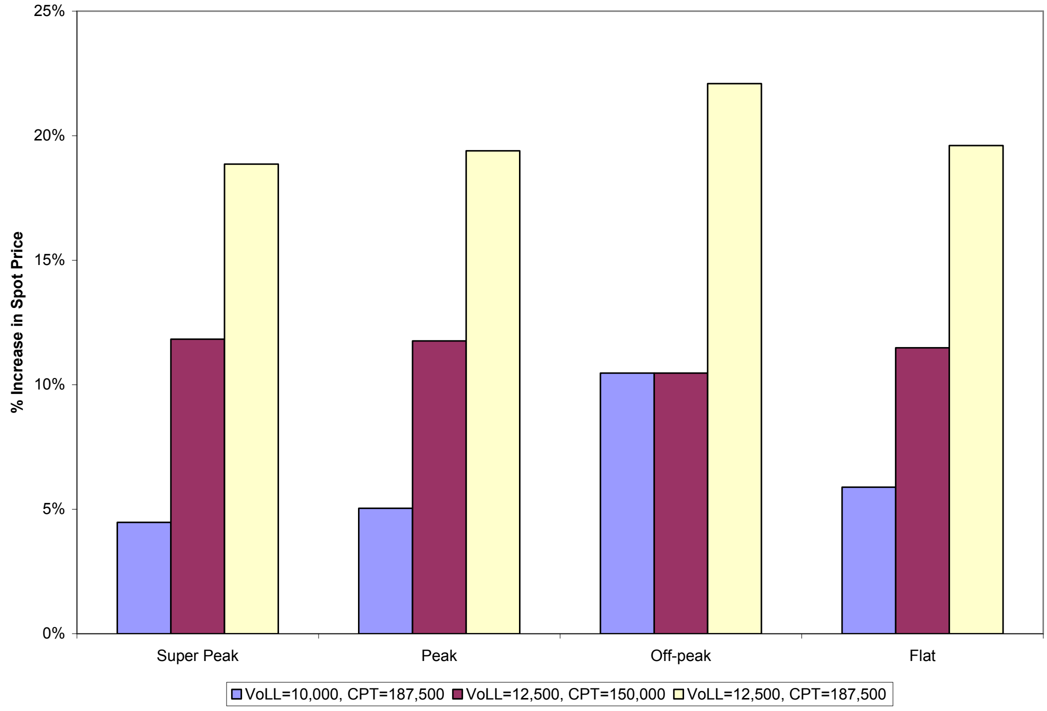


Table 10 summarises the price differential, in the form of a $/MW (for the week) cost for a constant 1 MW load, between spot prices for the week for the high VoLL-CPT scenario (VoLL = $12,500 and CPT = $187,500) and the base case (VoLL = $10,000 and CPT = $150,000). The minimum, maximum and average values correspond to the distribution of prices across the random samples. Depending upon the incidence of outages, demand and associated bidding behaviour, the increase in spot purchase costs may vary considerably. Considering that an (unhedged) retailer already faced a very high energy purchase costs, a further increment in costs may present a significant risk. A retailer with 1,000 MW demand would have to pay an additional $11.6 million in NSW and $14.3 million in SA for a single week. These costs are sufficiently high to offset a major part of the net annual profit earned by most retailers in the NEM. In the short term, retailers will face serious financial consequences and run into severe cash flow problems. If either of these high price events were to recur in future, the additional costs may significantly diminish the retail margin for unhedged retailers.

Even if a retailer is properly hedged against price volatility, an increase in peak prices will put pressure on contract prices and will ultimately feed into the retailer costs, albeit the short term impact for such a retailer will be far less onerous than an unhedged retailer.

Table 10 Increase in Spot Energy Purchase Cost ($/MW for the week)

	Minimum	Maximum	Average
Assuming a constant 1 MW load for all half-hour periods			
SA in March 2008	$13,699	$15,816	$14,297
NSW in June 2007	$9,944	$14,462	$11,677

Note: Increase in spot purchase cost is calculated as the difference between high VoLL-CPT scenario (i.e., VoLL=$12,500/MWh and CPT=$187,500) and base case (VoLL=$10,000/MWh and CPT=$150,000). Minimum, maximum and averages are calculated across the random samples.

A flat 1 MW load does not fully reveal the risk impact, especially for SA, which has a "peaky" load shape with a load factor below 70 per cent.[60] It is expected that, in most cases, retailers will have a higher exposure to peak prices compared to a flat load. We have therefore constructed three profiled load shapes, namely:

a. The actual load shape for the week, to which we have allocated 1 MW load for the peak half-hour and proportionally lower load for all other 335 half-hour periods. This yields a total of 116 MWh for the week, implying a load factor of approximately 69 per cent for the week. This is much lower than the 168 MWh (i.e., 336 half-hours * 1 MW) for a flat 1 MW load considered in the previous example in Table 10;

b. 10 per cent higher consumption during peak compared to (a), but keeping the total consumption for the week to 116 MWh; and

c. 10 per cent lower consumption during peak compared to (a), but keeping the total consumption for the week to 116 MWh.[61]

60 Load factor is defined as the ratio of average to peak load for the period.

61 Since there are many possible allocations of energy, we have used a linear program to allocate the energy in all cases so as to minimise the total purchase cost for the week for the load, i.e., the allocation will meet the higher, or lower, peak requirements for cases (b) and (c) and ensure load is shifted to keep overall purchase costs to a minimum in both cases.

Table 11 shows the results for these three cases. Energy purchase costs increase by $9,000 for the base case but are higher, at approximately $12,000, for the high VoLL-CPT scenario, indicating that a "peaky" load is naturally more susceptible to the spot price volatility. On average, the high VoLL-CPT scenario increases energy purchase costs by $28,861 if peak consumption is 10 per cent higher, compared to an increase of $26,747 of energy purchase costs for the actual load shape, i.e., a further increase of energy purchase costs by approximately 8 per cent.

Table 11 Comparison of Energy Purchase Cost ($/MW for the week): SA in March 2008

	Minimum	Maximum	Average
(A) Base (VoLL=10,000 and CPT=150,000)			
Actual load shape	$64,298	$69,193	$65,024
10 % higher peak period energy	$68,894	$73,981	$69,639
10% lower peak period energy	$63,111	$67,908	$63,822
(B) High VoLL-CPT (VoLL=12,500 and CPT=187,500)			
Actual load shape	$77,143	$83,772	$78,397
10 % higher peak period energy	$82,792	$89,976	$84,070
10% lower peak period energy	$75,698	$82,193	$76,927
Increase in Spot Energy Purchase Cost: (B) – (A)			
Actual load shape	$12,845	$14,579	$13,374
10 % higher peak period energy	$13,899	$15,995	$14,431
10% lower peak period energy	$12,587	$14,285	$13,105

Note: Minimum, maximum and averages are calculated across the random samples.

The overall cost increase for a retailer translates into $13,000-$14,000 per MW (or $13-14 per kW) for a retailer in SA depending on its load shape. Since the retailer already is exposed to $75,000 per MW or more for the week, this additional cost will take the total cost to approximately $90,000 per MW or $90 per kW for the week. Had the retailer been fully exposed to this cost and wanted to pass it onto a customer (assuming regulatory processes allow the retailers to do so), an average customer with 2.5 kW load would have to pay $225 in electricity bill for a single week. A retailer would in all likelihood be protected via cap contracts for such periods but the added $13-14 per kW would still add considerably to such contract prices and an additional cost of $33-35, if not more depending on their load shape, would ultimately be borne by customers. Assuming an annual electricity expenditure of $1000, this represents up to a 3.5 per cent rise in electricity bill if one of these extreme price events were to recur every year. If we assume such extreme events are more, or less, frequent, the customer cost impact will vary. If for instance, these extreme events are likely to occur once every five years, the impact will be less than 1 per cent on an annual basis for a typical customer.

4.3.2. Generator risks – Net Revenue Risks

Generator net revenues are calculated as the spot market revenue less direct operating costs. A rise in VoLL and/or CPT generally increases spot prices and, hence, generators earn higher margins. If both VoLL and CPT are increased, net revenue for generators in all regions including SA (in March 2008) and NSW (in June 2007) improve. An increase in super peak price is of particular relevance to peaking generators. SA prices during March 2008 increase by $1,752 if VoLL and CPT both increase. Over a 7.5 hour period, this earns a generator an additional $13,000 for the week – or approximately 20 per cent of a peaking generator's annualised fixed cost. In NSW, the super peak prices in June 2007 improved by over $1,000. Over a 7.5 hour duration, this recovers around 12 per cent of a peaking generator's annualised fixed cost. Increasing the VoLL-CPT therefore is expected to encourage investment in peaking capacity.

Generators face a mixed outcome if VoLL is raised but CPT is retained at $150,000. Downside risk only arises for cases when the CPT is breached and prices capped at the APC render a lower spot market revenue compared to the base case.[62] (The base case is shown in the top left hand quadrant of Table 12) Such a case arises for SA generators when VoLL is raised to $12,500/MWh but CPT is retained at $150,000 (see the upper right hand quadrant of Table 12). Although super peak net revenue figures are marginally higher because of the higher VoLL, peak period net revenues drop relative to the base case and off-peak period net revenues drop significantly. Overall, net revenue across all periods decreases 11 per cent from $648 to $576. If VoLL is relatively high, generator offers for non-peak periods will be adjusted to reap the high profit margins during super peak periods. However, in the event that outages or a demand surge leads to a CPT breach, an APC will lower the spot market revenue very substantially for APP. Further, the off-peak period net revenues leading to the CPT breach will also be low. It should be noted though that, even if we ignore compensation:[63]

- A peaking generator running on gas at a direct operating cost of $65/MWh would earn net revenues of more than $65,000/MW (as we have discussed before), and would earn more than its annualised fixed costs in this week alone. Similarly, NSW prices in June 2007 were high enough to earn a net revenue of $58,000/MW or 92 per cent of the annualised fixed costs (or 104 per cent of the annual capital requirement); and

- A peaking generator running on oil at an estimated cost of $355/MWh would also earn over $55,000/MW or 87 per cent of the annualised fixed cost. NSW prices in June 2007 exceeding $355/MWh yields net revenues for the week of $47,000/MW or 75 per cent of the annualised fixed cost (or, 84 per cent of the annual capital requirement).[64]

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62 The discussion ignores compensation payments for the moment.

63 As noted above, compensation is discussed in a separate Concept report.

64 As both the actual and the simulated prices show, there were a number of periods when prices were below the operating costs for peaking generators. Therefore the generator revenue leading up to the breach was not necessarily $150,000 and, in some cases, significantly below that level. Although this is somewhat specific to the price events studied, a predominantly thermal system is known to exhibit price patterns that are dominated by very high prices that quickly revert to normal levels.

Therefore, even if CPT is not raised, high prices leading to a CPT breach should generally provide generators with the bulk of the annual return needed to sustain their investment. We note however again that this falls well short of the original intent of the CPT, which is to provide 1.5 times (or 150 per cent) the annual capital requirement, in part, because capital costs for generation have increased since the CPT was set in 2000.[65] Annual capital costs were estimated at $50,000/MW/year in 2000 and the latest estimate puts these at $56,000/MW/year.[66] If a minimum return of 150 per cent is still deemed to be the dominant criterion, an increase in CPT may be justified in light of the increase in capital costs. Moreover, a mechanism may be required to adjust CPT periodically, as generation capital costs change over time.[67]

As Table 6 results show, leaving the CPT at $150,000, CPT breaches would occur more frequently and this in a way offsets the benefits of a higher VoLL. In the long term, if the current CPT persistently mutes the effect of a higher VoLL, this will discourage peaking investment, especially if the current trend of escalating generation capital cost continues in future. If adverse weather conditions recur and some of the planned capacity addition is delayed, or abandoned, the NEM reliability standard may be jeopardised.

However, to put this issue into perspective:

- If the CPT is set at 150 per cent of say $63,000/MW/year (which is the annualised fixed cost inclusive of fixed O&M costs) or $189,000, and the VoLL is increased, the outcomes will be similar to our high VoLL-CPT scenario. This shows a clear trade-off between retailer and generator risks. Setting CPT on this basis therefore requires careful assessment;
- A related issue is it requires a view on price volatility in general and not just *extreme* price volatility, which should be the basis of setting the CPT. If prices are generally high but remain well below the current CPT of $150,000, a peaking generator should be able to earn an adequate return. For instance, NSW prices during the 2007 winter were high enough to earn well over $63,000/MW for the year; and
- If, however, prices throughout the year never rise high enough to sustain such peaking investment, this is symptomatic of an excess capacity rather than a problem with the CPT level and additional peaking investment is not needed barring any reliability entry under such circumstances.

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65 Reliability Panel's review of VoLL in 1999 had determined a CPT of 300,000 to "allow a marginal supply side investment with a capital cost of approximately $400/kW to earn up to 3 times its annual capital requirement of $50,000/MW/year before the administered price is applied". ACCC had subsequently determined the CPT to be set at $150,000 which allows for a return of 1.5 times (or 150 per cent) of annual capital costs.

66 ACIL Tasman projects OCGT annual capital costs to rise to $81,000/MW/year over the next 20 years.

67 This has been raised in the Comprehensive Reliability Review.

- To summarise, a balanced view must take into account both generator and retailer/customer risks. On one hand, retailers, especially unhedged retailers, will be subject to severe financial damages in the short term. If frequent extreme price events occur, all retailers or final customers, in the event they can pass the costs to customers, will see a more modest increase (namely, 3.5 per cent increase in their annual cost for each such price event). On the other hand, generators facing increasingly higher capital cost may fall well short of meeting a key net revenue criterion that the CPT mechanism is intended to deliver.

Table 12 Net Revenue Risk Faced by Generators: March 2008 Event

		VoLL $10,000								VoLL $12,500							
		Mean				Standard Deviation				Mean				Standard Deviation			
		SP	P	O	F	SP	P	O	F	SP	P	O	F	SP	P	O	F
CPT 150,000	NSW	1,528	59	51	55	924	14	15	10	1,645	64	55	60	1,057	18	17	12
	QLD		49	26	38		1	1	1		53	29	41		0	1	1
	SA	**7,651**	**865**	**358**	**648**	**116**	**24**	**31**	**18**	**7,684**	**829**	**223**	**576**	**252**	**24**	**36**	**12**
	VIC	5,948	99	222	162	657	49	27	27	5,964	109	225	169	1,404	60	44	34
	SNY	935	96	163	118	353	4	34	12	1,000	104	175	128	382	4	38	13
	TAS		59	55	57		1	2	1		60	56	58		1	2	1
CPT 187,500	NSW	1,623	63	55	59	940	14	15	10	1,747	69	59	64	1,109	18	18	12
	QLD		53	29	41		0	1	1		58	31	45		0	1	1
	SA	**8,313**	**932**	**379**	**696**	**55**	**24**	**31**	**21**	**9,403**	**1,041**	**407**	**772**	**161**	**29**	**42**	**23**
	VIC	6,180	104	232	169	533	50	28	27	6,892	114	259	188	838	60	34	33
	SNY	995	104	175	128	366	4	37	13	1,062	112	189	138	403	4	40	14
	TAS		60	57	59		1	2	2		62	58	60		2	3	2

Note: Net revenue is spot market revenue less direct operating costs. Compensation payments are not included. All price and costs are calculated on a half-hourly basis.

Table 13 Net Revenue Risk Faced by Generators: June 2007 Event

		VoLL $10,000								VoLL $12,500							
		Mean				Standard Deviation				Mean				Standard Deviation			
		SP	P	O	F	SP	P	O	F	SP	P	O	F	SP	P	O	F
CPT 150,000	**NSW**	**5,423**	**653**	**71**	**356**	**376**	**65**	**8**	**31**	**6,080**	**736**	**80**	**402**	**500**	**73**	**10**	**35**
	QLD	4,627	379	72	230	144	7	9	5	5,077	419	81	255	190	10	10	7
	SA	775	72	38	59	99	1	1	1	900	77	39	62	125	1	1	1
	VIC	4,655	416	66	245	556	39	6	20	5,054	452	71	266	643	45	7	23
	SNY	5,878	1,002	389	906	460	101	119	88	6,521	1,109	452	1,009	529	112	141	97
	TAS	176	86	62	77	51	11	5	8	180	91	66	82	55	13	7	11
CPT 187,500	**NSW**	**5,694**	**697**	**80**	**383**	**369**	**66**	**10**	**32**	**6,451**	**790**	**90**	**434**	**487**	**83**	**11**	**40**
	QLD	5,003	411	81	251	170	8	10	6	5,529	460	90	281	186	9	12	6
	SA	900	77	39	62	125	1	1	1	1,085	83	41	67	163	2	1	1
	VIC	4,879	441	71	260	560	39	7	20	5,357	483	76	284	684	47	7	24
	SNY	6,129	1,058	451	966	462	106	140	92	6,958	1,191	510	1,089	565	122	160	106
	TAS	180	91	66	82	55	13	7	11	184	96	71	87	58	15	9	13

Note: Net revenue is spot market revenue less direct operating costs. Compensation payments are not included. All price and costs are calculated on a half-hourly basis.

4.3.3. Inter-regional Price Differences for MNSP and IRSR

MNSPs and IRSR unit holders would be exposed to changes in inter-regional price differences and are subject to significant changes if VoLL/CPT are increased. These price differences would typically be very large when prices approach VoLL in the importing region but there is surplus capacity in the exporting region. The interconnector would reach its limit and the price difference across the interconnector may be several thousand dollars in extreme cases.

As VoLL and/or CPT is increased and one of the regional prices approach VoLL, the inter-regional price difference will also generally increase. As price in the importing region approaches the CPT, flows into the region will reach the interconnector limit and price differences may be very high.

Table 14 and Table 15 present the inter-regional price differences for all four time periods for the March 2008 and June 2007 price events, respectively. The interconnector capacity limit into SA during the March price event was substantially lower than the normal capacity limit of over 680 MW of Heywood and Murraylink combined. This led to the limit being reached and price differences were extremely high for several hours prior to breaching the CPT.

- Increasing the VoLL and/or CPT would further raise these differences, as the simulation results show. The SA-VIC price differential for super peak periods (i.e., when SA prices were above $1000/MWh) increases from approximately $6,000 in the base case to nearly $7,500 in high VoLL-CPT scenario. The price event in June 2007 was much more widespread than the one in March 2008 because it was driven by water restrictions in several regions of the NEM. Prices were therefore high, not just in NSW, but also in QLD and VIC. The inter-regional price differences, being differences between two high prices, were less prominent in some cases. A high VoLL-CPT in the presence of a widespread energy limitation does not necessarily increase the inter-regional price difference, nor produce any discernible pattern for risk assessment to MNSP/IRSR.
- During an APP, scaling back of regional prices may drastically change price differences and may even reverse prices across regions in some cases. However, because of the much lower prices during an APP, these do not raise significant risk issues for MNSP/IRSR.[68]

[68] There are some compensation issues for MNSP/IRSR unit holders, which we discuss in a separate Concept report.

Table 14 **Inter-regional Price Differences: March 2008 Event**

			VoLL $10,000								VoLL $12,500							
			Mean				Standard Deviation				Mean				Standard Deviation			
	Import	Export	SP	P	O	F	SP	P	O	F	SP	P	O	F	SP	P	O	F
	VIC	TAS	5,800	41	149	97	639	38	19	20	5,844	48	151	102	1,344	45	31	25
	TAS	VIC		2	7	4		1	1	1		2	7	5		1	2	1
	NSW	QLD	979	12	22	17	959	12	11	8	1,033	12	23	18	1,088	15	12	9
	QLD	NSW		0	0	0		0	0	0			0	0			0	0
CPT	NSW	SNY	127	5	3	4	239	12	3	7	135	6	3	4	255	15	4	8
150,000	SNY	NSW		4	5	5		0	0	0		3	5	4		0	0	0
	SA	VIC	5,999	582	14	285	257	26	1	12	6,717	649	11	315	298	30	2	14
	VIC	SA	129	11	5	8	459	26	15	15	2,351	14	63	39	1,396	32	34	20
	VIC	SNY	4,913	28	130	81	793	38	22	21	4,964	32	132	85	1,405	45	33	27
	SNY	VIC	6	0	0	0	41	0	1	0	81	0	2	1	150	0	3	2
	VIC	TAS	6,082	44	157	103	513	38	20	20	6,748	52	175	116	825	47	24	24
	TAS	VIC		2	7	5		1	2	1		2	8	5		1	2	1
	NSW	QLD	1,011	12	23	18	984	12	11	8	1,073	13	24	18	1,145	15	13	10
	QLD	NSW			0	0			0	0			0	0			0	0
CPT	NSW	SNY	135	5	3	4	255	12	4	7	144	6	3	4	271	15	4	8
187,500	SNY	NSW		4	5	4		0	0	0		3	5	4		0	0	0
	SA	VIC	6,553	636	13	310	273	27	1	13	7,452	719	15	350	316	32	2	15
	VIC	SA	124	10	5	8	448	26	15	15	169	13	7	10	591	32	19	19
	VIC	SNY	5,132	29	136	85	734	39	23	22	5,734	34	152	96	988	47	27	26
	SNY	VIC		0	0	0		0	0	0	7	0	0	0	47	0	1	1

Note: Inter-regional price differences are calculated as importing region price (normally the higher price) less the exporting region price (normally the lower price).

Table 15 Inter-regional Price Differences: June 2007 Event

			VoLL $10,000								VoLL $12,500							
			Mean				Standard Deviation				Mean				Standard Deviation			
			SP	P	O	F	SP	P	O	F	SP	P	O	F	SP	P	O	F
	VIC	TAS	4,455	305	17	154	589	35	6	17	5,844	48	151	102	1,344	45	31	25
	TAS	VIC		1	17	10		2	8	5		2	7	5		1	2	1
	NSW	QLD	2,387	286	8	140	332	53	1	25	1,033	12	23	18	1,088	15	12	9
	QLD	NSW	1	0	0	0	6	0	0	0			0	0			0	0
CPT	NSW	SNY	672	108	6	54	470	63	9	30	135	6	3	4	255	15	4	8
150,000	SNY	NSW		0	3	1		0	0	0		3	5	4		0	0	0
	SA	VIC	5	0	6	3	31	0	0	0	6,717	649	11	315	298	30	2	14
	VIC	SA	4,300	292	15	147	586	34	5	16	2,351	14	63	39	1,396	32	34	20
	VIC	SNY	23	2	1	1	91	5	0	2	4,964	32	132	85	1,405	45	33	27
	SNY	VIC	1,762	154	15	81	413	33	9	16	81	0	2	1	150	0	3	2
	VIC	TAS	4,677	324	19	164	599	36	6	17	5,126	356	21	181	716	43	7	21
	TAS	VIC		2	18	10		2	10	6		2	20	11		2	12	7
	NSW	QLD	2,338	281	9	138	338	54	2	26	2,813	335	11	165	422	67	2	32
	QLD	NSW	1	0	0	0	7	0	0	0	1	0	0	0	7	0	0	0
CPT	NSW	SNY	688	110	6	56	470	63	10	30	824	133	7	67	587	79	11	37
187,500	SNY	NSW		0	2	1		0	0	0		0	2	1		0	0	0
	SA	VIC	4	0	5	2	29	0	0	0	4	0	4	2	26	0	0	0
	VIC	SA	4,496	311	17	157	595	34	6	16	4,909	342	20	173	712	41	6	19
	VIC	SNY	25	2	1	1	96	5	0	3	26	2	1	1	101	6	0	3
	SNY	VIC	1,808	161	17	86	420	35	10	17	2,230	193	20	103	521	41	11	20

Note: Inter-regional price differences are calculated as importing region price (normally the higher price) less the exporting region price (normally the lower price).

4.3.4. Summary of Financial Risk Assessment

An increase in VoLL and CPT together has a significant implication for risk from a retailer perspective. Retailers face a significant increase during peak periods (including super peak periods, which are defined as the top 7.5 hours when prices exceed $1,000/MWh). On average, prices increase by 20 per cent and the increase over the top 7.5 hours alone amounts to an additional VoLL event. Any spot purchase during these hours will leave a retailer exposed to an additional $1,000-$2,000 per MWh. This is also expected to influence peak contract prices.

The overall cost increase for a retailer translates into $13,000-$14,000 per MW for a retailer in SA depending on its load shape. Since the retailer is already exposed to $75,000 per MW or more for the week, this additional cost will take the total cost to approximately $90,000 per MW or $90 per kW for the week.

In the long term, a retailer without appropriate hedge cover may face serious financial consequences because each extreme price event may potentially wipe out a significant part of its net revenue margin for a year. Even if the retailer has hedged its risk against peak prices, the increased volatility will increase contract prices over time, albeit the cost impact will be far less onerous compared to the short term impact faced by an unhedged retailer.

If the retailer is able to pass the increase in costs to final consumers, the cost will ultimately be borne by them.[69] However, the added cost will be far less significant, as may be illustrated for a typical residential customer with a 2.5 kW load. An increase in cost of $13-$14 per kW will cost the load an additional $33-$35 per year if one of these events occurs every year. Assuming an annual electricity bill for a typical customer to be $1,000, this implies approximately a 3.5 per cent rise in electricity bill for an average customer if one of these events were to recur in a year. If we assume these extreme price events are likely to be less or more frequent, the impact will be lower or higher. For instance, if we assume a breach to be a 1-in-5 year event, the price impact will be less than 1 per cent.

Generators are generally better off with a rise in both VoLL and CPT using the representable weeks in NSW and SA. An increase in super peak period price alone would earn the NSW and SA generator an additional $13,000 and $7,500 per MW in net revenue for the week, respectively. These represent 20 per cent and 12 per cent of annualised fixed costs for a new green-field peaking generator. The overall price increase for these two weeks adds considerably more to net revenues. SA and NSW generators are expected to see on average increase in net revenue of, respectively, $124 and $79 per MWh over the week.

Generators face a mixed outcome if VoLL is increased to $12,500 but the CPT is retained at $150,000. The CPT is breached and prices are capped at APC for a significant number of periods. This affects generator net revenue outcomes (ignoring compensation payments, which should improve net revenues). This indicates a potential downside to keeping the CPT low relative to VoLL. It should be noted though that even if we ignore compensation:

69 There will be regulatory risks that may or may not allow such pass through. In the event that a retailer is not able to pass the cost, this implies a short term increase in costs faced by the retailer.

- A peaking generator running on gas at a direct operating cost of $65/MWh would earn net revenues of more than $65,000/MW for the week, and would earn more than its annualised fixed costs in this week alone. Similarly, NSW prices in June 2007 were high enough to earn a net revenue of $58,000/MW or 92 per cent of the annualised fixed costs; and
- A peaking generator running on oil at an estimated cost of $355/MWh would also earn over $55,000/MW for the week, or 87 per cent of the annualised fixed cost. In the June 2007 case, NSW prices exceeding $355/MWh yields net revenues for the week of $47,000/MW or 75 per cent of the annualised fixed cost of the OCGT.

Therefore, even if CPT is not raised, high prices leading to the point of breaching the threshold should generally provide generators with the bulk of the annual return needed to sustain their investment. That said, this return falls well short of the 150 per cent of annualised capital cost that was intended in the original setting of CPT. There is clearly a trade-off in setting the CPT, and retaining the CPT at the current level will not serve one of the main goals that was set out to ensure adequate return to generators.

In the long term, if the current CPT persistently mutes the effect of a higher VoLL, this will discourage peaking investment especially if the current trend of escalating generation capital cost continues in future. If adverse weather conditions recur and some of the planned capacity addition is delayed, or abandoned, the NEM reliability standard may be jeopardised.

Inter-regional price differences during an extreme price event may be high if high prices tend to be localised rather than widespread, as happened to be the case in the March 2008 event. Increasing the VoLL and/or CPT would further increase these differences, as the simulation results show. The SA-VIC price differential for super peak periods (i.e., when SA prices were above $1000/MWh) increase from approximately $6,000 in the base case to nearly $7,500 in high VoLL-CPT scenario. The price event in June 2007 was much more widespread than the one in March 2008 because it was driven by water restrictions in most parts of the NEM. Prices were therefore high, not just in NSW, but also in QLD and VIC. The inter-regional price differences, being differences between two high prices, were less prominent in some cases. A high VoLL-CPT in the presence of a widespread energy limitation does not necessarily increase the inter-regional price difference, nor produce any discernible pattern for risk assessment to MNSP/IRSR.

During an APP, scaling back regional prices may drastically change price differences and does even reverse prices across regions in some cases. However, because of the much lower prices during an APP, these do not have raise significant risk issues for MNSP/IRSR.

5. SUMMARY OF FINDINGS

This study has reviewed a wide range of issues that are relevant to the assessment of financial risk for market participants in the NEM. Recent high price events provided the necessary impetus and context for looking into these issues. Accordingly, the study used two of the recent high price events to explore the factors that drive high prices and what implication these hold for financial risk for retailers and generators among others.

We have summarised our key findings in response to the issues that were raised in the terms of reference.

"A conceptual assessment of the impact of the proposed increase in the levels of VoLL and CPT on financial risk to each participant class, including end users. In particular, the assessment should consider the current bidding behaviour of participants and how this behaviour would be expected to be modified by the proposed increase in the levels of VoLL and the CPT."

Our theoretical analysis, and to some extent the limited evidence from recent high price outcomes, suggests that a binding CPT would influence the profit maximising strategy for generators. Increasing the CPT provides more opportunity for a generator to bid aggressively, which not only affects peak prices but also non-peak prices. There are also indirect pricing effects for other regions that may not have a binding CPT. We have used an inter-temporal modelling framework that explicitly models the CPT as a constraint on prices over consecutive days.

A simultaneous increase in both VoLL and CPT therefore introduces a risk that generators can bid more aggressively – and for longer period – without the risk of violating the CPT. We have therefore used the modelling analysis to explore scenarios wherein we study alternative scenarios when VoLL or CPT is increased (but not both). We recognise that keeping CPT the same introduces a risk of discouraging peaking investment which is also an element of market risk that we have studied.

We have assessed qualitatively if a generator would choose to adopt a strategy to breach the CPT and maximise its gain from the sum of high spot prices leading up to the CPT *and* compensation payments. We have formed a view that given the significantly different drivers of bidding before and during an APP and the uncertain nature of events that lead to a breach, it will be difficult if not impossible for a generator to adopt a strategy that *a priori* maximises this combined profit. A generator therefore is likely to avoid breaching a CPT, and instead will seek to maximise the profit from high prices while keeping it within the CPT. If uncertain events lead to a CPT breach, depending upon compensation arrangements in place, generators *during an APP* may have a perverse incentive to aggressively bid a significant part of its capacity above the APC to maximise compensation payments.

There is limited experience to date to draw any conclusive evidence from the actual NEM experience. Nevertheless, the high price events during March 2008 and subsequent analysis by the AER provides some evidence to suggest that generators in SA had exhibited aggressive bidding behaviour in times of high demand and low interconnection. AER's analysis also suggests that, in some cases, generators showed a tendency to remain within the CPT rather than breach it, even when high demand provided them ample opportunity to breach the threshold.

Market modelling to test the conceptual assessment described above and to provide further explanation of the financial risks to different participant classes.

The market modelling explicitly considered two recent high price events, namely, high prices in SA in March 2008 and the NSW price events in June 2007. High demand in combination with other factors (e.g. low interconnection availability into SA and shortage of water for hydro as well as coal plants in NSW/QLD), were the physical drivers that caused these high price events. However, in both cases, extreme generator bidding behaviour was observed to contribute to high prices.

Although the market modelling is relatively simple (e.g., ignored ancillary services) and has limitations on data for some of the uncertain drivers (e.g., interconnection outage probability), we have calibrated the model against the actual events reasonably well. Simulated prices reflect that a combination of stressed system conditions and generator bidding behaviour may have led to these high price events.

Based on our conceptual assessment, we have explored four scenarios combining two levels of VoLL, namely, $10,000 and $12,500 with two levels of CPT, namely, $150,000 and $187,500. We have referred to the current settings of VoLL ($10,000) and CPT ($150,000) as the base case. The market simulation results show that:

- Raising CPT to $187,500 together with an increase in VoLL to $12,500 leads to a 20 per cent increase in cumulative prices overall relative to base case;
- In comparison, if VoLL is increased to $12,500/MWh but the CPT is retained at $150,000, SA prices will increase by less than 1 per cent, i.e., a CPT of $150,000 in combination with an APC would have been effective in curbing the spot price volatility leading up to the administered price period;
- The combined impact of increasing both VoLL and CPT translates into an increase in total spot market purchase cost of $27 million in SA over March 11-17 in 2008 and $117 million in NSW over June 12-17, 2007. These additional spot purchase costs may add significantly to the burden for retailers depending on the risk management strategy they have in place; and
- Increasing the VoLL alone significantly raises the risk of breaching the CPT of $150,000 for both SA and NSW. A commensurate increase in the CPT to $187,500 along with an increase in VoLL to $12,500/MWh reduces this risk to a level comparable to that in the base case (i.e., VoLL is $10,000/MWh and CPT is $150,000). However, as the preceding observations suggest, prices increase appreciably in both SA and NSW that reflect a more aggressive bidding pattern by the generators and hence a significantly higher frequency of high price events.

VoLL-CPT changes impact differently upon the risks faced by individual participants.

Generators face a mixed outcome. In the short term:

- An increase in super peak period price alone would earn the NSW and SA generator an additional $13,000 and $7,500 per MW in net revenue for the week, respectively. These represent 20 per cent and 12 per cent of annualised fixed cost for a new green-field peaking generator. The overall price increase adds considerably more to the net revenue. SA and NSW generators are expected to see on average increase in net revenue of, respectively, $124 and $79 per MWh over the week;

- If VoLL is increased to $12,500 but CPT is retained at $150,000, the CPT is breached and prices are capped at APC for a significant number of periods. This affects generator net revenue outcomes.[70] This indicates a potential downside to keeping the CPT low relative to VoLL. It should be noted though that even if we ignore compensation, a peaking generator would earn between 75 to 92 per cent of its annualised fixed cost (or 84 per cent and 104 per cent of the annualised capital requirements, respectively) in a single week. Therefore, even if the CPT is not raised, high prices leading to the point of breaching the threshold should generally provide generators bulk of the annual return needed to sustain their investment. Having said that, this return falls well short of the 150 per cent of annualised capital cost that was intended in the original setting of CPT. There is clearly a trade-off in setting the CPT, and retaining the CPT at the current level will not serve one of the main goals that was set out to ensure adequate return to generators; and

In the long term, if the current CPT persistently mutes the effect of a higher VoLL, this will discourage peaking investment especially if the current trend of escalating generation capital cost continues in future. If adverse weather conditions recur and some planned capacity additions are delayed, or abandoned, the NEM reliability standard may be jeopardised.

Retailers and other wholesale market energy purchasers face a cost increase. In the short term:

- A significant increase in purchase costs of any unhedged load during the peak periods (including super peak periods, which are defined as the top 7.5 hours when prices are exceed $1,000/MWh). On average, prices increase by 20 per cent and the increase over the top 7.5 hours alone amounts to an additional VoLL event;

- The overall cost increase for a retailer exposed to spot prices translates into $13,000-$14,000 per MW for a retailer in SA depending on its load shape. Since the retailer is already exposed to $75,000 per MW or more for the week, this additional cost will take the total cost to approximately $90,000 per MW or $90 per kW for the week. This implies approximately a 3.5 per cent rise in electricity bill for an average customer if <u>one</u> of these events were to recur in a year;

In the long term, such cost increases would over time translate into higher contract purchase costs to insulate them from a higher spot price exposure.

Participants with exposure to inter-regional price difference will generally see an increase in price differentials:

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70 This ignores any compensation payments.

- Increasing the VoLL and/or CPT would further raise these differences as the simulation results show. SA-VIC price differential for super peak periods (i.e., when SA prices were above $1000/MWh) increase from approximately $6,000 in the base case to nearly $7,500 in high VoLL-CPT scenario. The price event in June 2007 was much more widespread than the one in March 2008 because it was driven by water restrictions in most parts of the NEM. A high VoLL-CPT in presence of a widespread energy limitation does not necessarily increase the inter-regional price difference, nor produce any discernible change in the pattern for risk assessment to MNSP/IRSR.
- During an APP, scaling back regional prices may drastically change price differences and may even reverse prices across regions in some cases. However, because of the much lower prices during an APP, these do not raise significant risk issues for MNSP/IRSR.

5.1. CONCLUDING REMARKS

This study has focused on the drivers of high price events and comprehensively covers:

- Theoretical analysis of generator bidding and CPT;
- Examination of available empirical evidences; and
- Market modelling analysis.

These analyses suggest a combination of aggressive generator bidding and stressed system conditions (such as high demand and limited generation availability) as the primary driver of these high price events, rather than physical drivers alone. Increasing VoLL and the CPT provides generators with greater scope for bidding aggressively without the risk of breaching the (higher) CPT.

Market simulations around two recent high price events reveal that, if both VoLL and CPT are increased, (cumulative) prices may rise as much as 20 per cent on an already high level for the selected weeks. Under extreme system conditions that prevailed in recent months, an increase in VoLL and CPT will add significantly to the energy purchase cost risk faced by a retailer. Prices in general over a longer period, e.g., several months or a year, will not be affected as much because such extreme events are expected to occur infrequently. Assuming the retailer passes on the added costs to final customers, a typical customer bill is expected to increase by 3.5 per cent if an extreme price event occurs every year, or less if such events occur less frequently.

On the other hand, if VoLL alone is increased without a commensurate increase in the CPT, generators face the prospect of a lower revenue outcome. Although the generators are able to recover most of its annualised fixed costs, the net revenue falls well sort of the 150 per cent of annual capital requirement that was intended to be one of the criteria in determining the CPT. If the CPT is retained at $150,000 and VoLL is raised, this also materially increases the risk of breaching the CPT.

The final selection of CPT and VoLL therefore needs to strike a balance:

- If both CPT and VoLL are raised, there is the potential for an increase of up to 20 per cent in spot prices if an extreme price event such as those in March 2008 or June 2007 were to occur. This translates into a 3.5 per cent increase in an average customer's annual bill if one of these events occurs in a year, and less than 1 per cent if it occurs once every five year. A commensurate increase in CPT with VoLL also helps to contain the risk of a CPT breach approximately at the same level at the current level.
- If CPT is retained at $150,000, but VoLL is raised, a typical peaking generator recovers the bulk of its annual fixed costs, but falls well short of the 150 per cent of annual capital requirement criterion that was set out by the Reliability Panel/ACCC in 1999-2000. Retaining the CPT at $150,000 also substantially increases the risk of breaching the CPT once VoLL is raised.

APPENDIX A TERMS OF REFERENCE

The Australian Energy Market Commission asked Concept Economics (“Concept”) to provide advice to the Reliability Panel (“the Panel”), on the impacts of proposed increases in the value of lost load (“VoLL”) and the cumulative price threshold (“CPT”) on:

- The financial risk faced by participants in the National Electricity Market (“NEM”);
- The level of systemic, market-wide risks; and
- The efficiency and efficacy of the packages of VoLL, CPT, Administered Price Cap (APC) and compensation arrangements and their settings in mitigating systemic, market-wide risk at times of extreme financial stress.

Specifically Concept has been asked to provide the Panel with a written report on the following issues:

1. A conceptual assessment of the impact of the proposed increase in the levels of VoLL and CPT on financial risk to each participant class, including end users. In particular, the assessment should consider the current bidding behaviour of participants and how this behaviour would be expected to be modified by the proposed increase in the levels of VoLL and the CPT.
2. Market modelling to test the conceptual assessment described above and to provide further explanation of the financial risks to different participant classes.
3. The conceptual assessment and the market modelling should consider a range of scenarios with different compensation arrangements that could apply during administered price periods to determine the impact on the financial risks to different participant classes:
    a. Compensation based on “direct operating costs:, i.e. short run marginal costs (SRMC) excluding opportunity costs;
    b. Compensation based on SRMC including the opportunity costs of fuel restricted plant, such as hydro and gas; and
    c. Compensation based on the bids and offers of market participants.

The report is required to further assess:

1. The factors that cause sustained high prices and the influence these have had during past events where the cumulative prices have come close to breaching or have breached the CPT. These might include high demand, interconnector outages, generator outages, fuel supply interruptions, and the misuse of market power;
2. The impact of an increase in the levels of VoLL and the CPT on the financial risks faced by individual market participants (i.e. retailers, generators, traders, generator-retailers, market network service providers (“MNSPs”), inter-regional settlement residue (“IRSR”) unit holders etc);

3. The behavioural incentive effects arising individually from the settings of VoLL, CPT, APC and compensation arrangements and the impact of these on risk;
4. The effects of the changes in the setting on the systemic, market-wide, financial risks that the total package of CPT-APC and compensation is designed to mitigate;
5. The effectiveness and efficiency of the package in meeting its objective of mitigating market-wide financial risk arising from sustained periods of extremely high prices; and
6. Potential enhancements (and/or alternatives) to the existing arrangements for mitigating market-wide risk from high priced events.

APPENDIX B REVIEW OF PRIOR MODELLING STUDIES

B.1. INITIAL RELIABILITY PANEL - MODELLING ON VOLL AND CPT (1999)

When introduction of the VoLL and CPT mechanisms was recommended for authorisation to the ACCC by the NECA Code Change Panel reliance was placed on some initial modelling undertaken by the Reliability Panel estimating the incidence and duration of CPT breaches.

This modelling used a simple spreadsheet of prices of a 24 day period, and assumed as an input the Panel's recommended set of arrangements which were a VoLL of $20,000 and a CPT of $300,000.

Four scenarios were assessed, including:

- Brief excursions to an extreme price from a low base;
- Long series of very high daily peak prices from day 11 and low shoulder and off-peak;
- High price lead-in to extreme conditions for extended periods; and
- Low price lead-in to brief but repeated extreme conditions.

Under these scenarios the return to a new entrant OCGT were measured, and the level of reliability was compared to the target reliability standard. The modelling approach adopted was basic. According to available information, the modelling does not appear to have incorporated:

- Market simulations,
- Strategic bidding behaviour, and
- Probabilistic (Monte Carlo) assessment of network outages or generator outages.

B.1.1. IES MODELLING – ACCC AUTHORISATION (2000)

As part of its consideration of the NECA's proposed Code changes relating to VoLL and CPT the ACCC commissioned Intelligent Energy Systems to model the impact of various levels of VoLL and the CPT in the NEM.

The IES study focused on how an increase in VoLL could affect average annual spot price, price volatility and price incentives for new generation in the NEM. The study was undertaken using IES's market simulation model, PROPHET, based on a "generic region", understood to be Victoria in the year 2006. This effectively represented a medium size region on the verge of requiring additional supply side capacity.[71]

The study modelled six independent variables:

1. Generator bidding.

[71] ACCC Final Determination – Application for Authorisation: VoLL, Capacity Mechanisms and Price Floor, 20 December 2000, p.33

2. Generator outage - Normal (currently observed rates of up to 5%) and two extreme scenarios, namely,
    a. Catastrophe A (1000 MW of base load lost over the three winter months); and
    b. Catastrophe B (2000 MW of base load lost over three winter months).
3. Generating reserve margin - Low (100 MW), Medium (600 MW), and High (800 MW).
4. Demand management - Low (none); Medium (up to 3% at a spot price of $3000/MWh); High (voluntary clearing of the market at a spot price of $3000/MWh).
5. VoLL - $5000/MWh; $10,000/MWh; $20,000/MWh.
6. CPT - No limit; $300,000/MWh; $150,000/MWh.

Specifically, under various demand management conditions the study investigated the effects of VoLL and the CPT on new entry price signals, market risk, supply reliability and generator bidding behaviour. The levels of VoLL and CPT modelled were:

- VoLL of $5,000/MWh;
- VoLL of $10,000/MWh combined with CPTs of $150,000 and $300,000; and
- VoLL of $20,000/MWh combined with CPTs of $150,000 and $300,000.

The IES study used pre-defined outage scenarios, and tested the role played by the CPT in capping market risk. In addition to the base case based on past outage history, IES modelled two catastrophic scenarios of generator outages discussed above.

The scenarios had the expected effect of significantly raising spot prices, new entry premiums and risk premiums, with the increase magnified the higher the level of VoLL. The modelling found the CPT to be largely ineffective in managing this increase in risk.

The IES analysis found that, under Scenario A, the CPT was not invoked, illustrating that market risk would not be expected to reach the level at which the CPT would operate even under loss of significant generation. The modelling found that only in the case of Scenario B did a CPT of $150,000 significantly reduce market volatility. Based on these catastrophic scenarios, the study concluded that a loss of 1500 MW to 2000 MW of base-load generator would trigger cumulative spot prices over 336 consecutive dispatch periods sufficient to breach suggested CPT levels.

The overall findings of the IES report were:

- Given historical bidding patterns, a VoLL of $5,000/MWh is sufficient to support the level of economic generator capacity necessary to satisfy NEMMCO reserve levels;
- Depending upon the level of demand side responsiveness assumed, increasing VoLL from $5,000/MWh to $20,000/MWh increases price risk by up to a factor of four;
- Depending upon the level of demand side responsiveness, generator bidding assumptions and generator reserve levels, increasing VoLL from $5,000/MWh to $20,000/MWh increases annual average spot prices in the NEM by between $1/MWh and $7/MWh; and

- The CPT would be ineffectual in capping market risk in all but the most extreme circumstances.[72]

The ACCC Final Determination placed considerable reliance on these findings to support its reductions to NECA's proposed levels of VoLL and the CPT (reducing these to $10,000/MWh and 150,000 respectively).

B.1.2. CRA INTERNATIONAL MODELLING – COMPREHENSIVE RELIABILITY REVIEW (2007)

CRA International (CRA) provided further modelling on a range of issues including the interaction of a suite of revised VoLL and reserve market arrangements as part of the AEMC's most recent Comprehensive Reliability Review.

A key objective of the modelling was to assess whether current market settings, including the level of VoLL, would likely to continue to deliver the NEM reliability standard of 0.002% USE across the NEM and in region.

The CRA modelling took into account:

- Long term market expansion,
- Transmission and reserve constrained generation dispatch,
- Strategic bidding scenarios,
- Fuel cost, load growth and its temporal/spatial distribution and new entrant capital expenditure,
- A Monte Carlo 'engine' to randomly generate potential outages,
- Ancillary services (represented as a single spinning reserve requirement), and
- Analysis of half-hourly prices to assess CPT breaches.

The modelling showed that there were significant risks that the reliability standard would not be met in the future. This formed the basis for the Reliability Panels recommendation to raise the VoLL to $12,500/MWh from 1 July 2010.

In relation to CPT, the modelling indicated a 'negligible' possibility of breach in the near future at the current market setting of $150,000. The modelling did, however point to a rising risk of breach over time, with indications that the CPT could be breach in one or two weeks a year in the next few years. The report, however, pointed to a number of factors outside of the model such as contract or demand side measures that were expected to reduce the risk.[73]

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72 ACCC Final Determination – Application for Authorisation: VoLL, Capacity Mechanisms and Price Floor, 20 December 2000, p.34

73 CRA International, Comprehensive Reliability Review, Design Option Analysis Appendix, Figure 22, p.33

APPENDIX C TECHNICAL DESCRIPTION OF THE MODEL

We have provided below an exposition to the mathematical model used to simulate Cournot, Bertrand and Perfect Competition paradigms in an electricity market. The same general construct apply for each of these three paradigms in the form of a conjectural variation.[74] We have presented a Cournot approach first and then discussed the variations around it and have also discussed the implications for prices.

The basic premise of the strategic bidding model is that the firms (namely, portfolio generating companies in the NEM) take an individual profit maximizing position by withdrawing production to increase prices above the marginal cost of production. Each firm is sufficiently large to influence market price received by all, and the quantity produced by other firms. Each firm maximizes its own profit given the quantity chosen by other firms expressed as,

$$\pi^i(q_i, q_{i'}) = q_i P(q_i, q_{i'}) - C_i(q_i)$$

where,

π^i (.)	Profit of firm/player *i* given the production strategy of all other players *i'*
q_i	Production strategy of player *i*
P(.)	Price as a function of all *q*'s i.e., firms *i,i'*, etc. This is the key characterization of an oligopolistic market that distinguishes such markets from a perfectly competitive one – players can influence market price by changing their production as opposed to a "price taker" behaviour exhibited in a competitive market
C_i(.)	Cost as a function of production strategy q_i.

The solution of the game is obtained by solving a set of simultaneous equations representing the first order optimality conditions for each firm *i*. A generalised form of this optimality condition for each player *i* is as follows,

$$p - c + q.P'(Q)\,(1+\lambda) = 0$$

where,

λ	Conjectural variation parameter $\sum_{n'\neq n} (\partial q_{n'}/\partial q_n)$. If $\lambda=0$, we have a Cournot conjecture in quantity competition and $\lambda=(-)1$ yields a Bertrand conjecture with intense price competition. Prices will strictly increase in the range **λ є [-1,0].**[75]

[74] Roman Inderst and Tommasso Valletti, *Market Analysis in the Presence of Indirect Constraints and Captive Sales*, Journal of Competition Law and Economics, 3(2), 203-231.

[75] Inderst and Valletti, *ibid*, p.210.

The transmission constrained strategic bidding model is formulated as[76]:

Maximize,

$$\sum_j [\alpha_j - \frac{1}{2}\beta_j Y_j] Y_j - \sum_i q_i C_i - \sum_{i,j} \frac{1}{2}\beta_j X_{i,j}^2 \quad (1)$$

Subject to,

$$\sum_{(i,j)\in\Omega} X_{i,j} + \sum_{(j',j)\in\Theta} F_{j',j} + \sum_{(j,j')\in\Theta} F_{j,j'} = Y_j \quad (2)$$

$$q_i = \sum_{j=1}^{M} X_{i,j} \quad (3)$$

$$\sum_{j=1}^{M} X_{i,j} \le X_i^{\max} \quad (4)$$

$$F_{j,j'} \le F_{j,j'}^{\max} \quad (5)$$

$q_i,\ X_{i,j},\ Y_j,\ F_{j,j'} \ge 0$

where,

i,j	Generating company and node indices
Ω	Association of company (generator) and nodes
Θ	Nodal connectivity i.e., connected pairs (*j,j'*)
Y_j	Net injection to node *j* (MW)
q_i	Generation by *i* (MW)
$X_{i,j}$	Generator *i* feeding node *j* (MW)
$F_{j,j'}$	Physical flow from node *j* to node *j'*
α_j, β_j	Linear inverse demand equation parameters, i.e., price is defined as, p = α_j, - β_j Y_j
C_i	Marginal cost of generator *i* ($/MWh)
$F_{j,j'}^{max}$	Transfer capability (MW)
X_i^{max}	Max generation capacity (MW)

76 Additional details on this formulation is available in: D. Chattopadhyay, *Multi-commodity Spatial Cournot Model for Generator Bidding Analysis*, IEEE Transactions on Power Systems, February, 2004.

Constraint (2) represents the nodal electricity balance. Equation (3) calculates the total generation from an incumbent company. The physical limits on generation and transmission are expressed in (4) and (5), respectively. Optimisation problem (1)-(5) presents a single optimisation problem for all the generators. However, as discussed before, the individual generator profit maximisation problems are implicit in this single optimisation. It is equivalent to the dispatch optimisation procedure for an oligopolistic market where generators attempt to withdraw generation to keep prices above marginal cost level. The solution of the non-linear programming problem involves finding the generation dispatch and associated flows across the nodes that maximises the welfare adjusted total market benefit. This solution automatically ensures that individual generator profit is maximised and it is the Cournot-Nash equilibrium outcome.

C.1. ALTERNATIVE PARADIGMS AND PRICING IMPLICATIONS

The model (1)-(5) can be modified to simulate

- a "Perfect Competition" (PC) paradigm by dropping the last term in the objective function, i.e., the maximand (1) reduces to,

$$\sum_j [\alpha_j - \frac{1}{2}\beta_j Y_j]Y_j - \sum_i q_i C_i \text{; and}$$

- a Bertrand Price Competition (BPC) paradigm by,
  - replacing the quantity variables with prices, and
  - using a demand function rather than inverse demand function.

The pricing implications of transmission constraints in a Cournot setup are complex and illustrated around a simple example. We present the pricing analysis for a simple two-node case. Node A and B has one generator each (1 and 2, respectively with constant marginal costs c_1 and c_2) and we assume the flow direction is from B to A. We use the following notations for the dual problem i.e., the "price" variables associated with the three constraints:

λ^j	nodal prices or the duals of the flow balance (2)
γ^j	marginal cost of supply or dual of (3), and
$\pi^{jj'}$	shadow price of transfer capability limit or dual of (5).

Differentiating the Lagrangian with respect to q_i, $X_{i,j}$ and $F_{j,j'}$, we obtain the following pricing relationships:

$\gamma^1 = c1; \gamma^2 = c2$

$-\beta^A X^{1A} + \lambda^A - \gamma^1 = 0$

$-\beta^B X^{2B} + \lambda^B - \gamma^2 = 0$

$\lambda^A - \lambda^B + \pi^{BA} = 0$

The marginal cost of supply in this case reflects the constant marginal cost of supply of the local generator. The nodal prices in a Cournot setting are functions of the demand elasticity adjusted nodal supply, and finally the shadow price on the flow constraint reflects the nodal price differences.

Combining the relevant terms, we get the following relationship between shadow price on flow and production:

$\pi^{BA} = (\gamma^2 - \gamma^1) + (\beta^B X^{2B} - \beta^A X^{1A})$

An important observation is that the constraint on flow has two effects:

- A flow constraint has the impact of creating a nodal price difference equal to difference in nodal marginal cost of supply. This is a well known feature of nodal/locational spot markets including the NEM; and
- The second one is specifically an outcome of a binding transmission constraint in a Cournot gaming context. Since generators can withdraw MW supply and increase price to earn super-competitive level profit, the elasticity adjusted production (e.g., $\beta^B X^{2B}$) represents the impact of withdrawal of local generation can have at the local node. The differential elasticity adjusted production is reflected in the shadow price of the constraint. This indicates the extent to which generators have pricing discretion. For instance, the difference in marginal cost between the importing and exporting regions may be partially offset if the local producer in the exporting region is able to maintain price in the exporting region well above its marginal cost.

C.2. MODELLING INTERTEMPORAL LINKAGES

One of the key issues that the modelling needs to address is the impact of a combined VoLL-CPT package. The modelling framework therefore needs to be extended to determine price and volume outcomes over a number of periods taking into account,

1. Generation capacity availability, i.e., to the extent generator capacity may be in or out of service; and
2. Cumulative price threshold as a constraint on price outcomes, namely if prices over the next *t* periods exceed certain level, prices will revert to an administered price.

Accordingly the gaming model is extended as follows:[77]

Maximize,

[77] This is an extension of the theoretical model: D. Chattopadhyay, *A Game Theoretic Model for Strategic Maintenance and Dispatch Decisions*, IEEE Transactions on Power Systems, Vol 19, No. 4, November, 2004.

$$\sum_t \left(\alpha_t - \frac{1}{2}\beta_t Y_t \right) Y_t - \sum_{i,t} X_{i,t} C_{i,t} - \sum_{i,t} \frac{1}{2} \beta_t X_{i,t}^2$$

(6)

Subject to,

$$\sum_i X_{i,t} = Y_t \forall t \quad (7)$$

$$X_{i,t} \le X_{i,t}^{\max} \cdot (1 - \phi_{i,t}) \forall (i,t) \quad (8)$$

$$\sum_t \phi_{i,t} = 1 \ \ \forall i \quad (9)$$

$$p_t = \alpha_t - \beta Y_t, p_t \le VoLL, \sum_t p_t \le CPT \perp p_t \ge p^a \forall t \quad (10)$$

$X_{i,t}$, $\Phi_{i,t}$, $Y_t \geq 0$

where,

t	Time period index, $t=1,\ldots,T$ weeks/months
Y_t	Total generation supply in t (MW)
$X_{i,t}$	Generator i generation in t (MW)
$\Phi_{i,t}$	Fraction of generator i unavailable capacity in t
α_t, β_t	Linear demand equation parameters for t
$C_{i,t}$	Marginal cost of generator i in t (\$/MWh)[78]
$X_{i,t}^{max}$	Max generation capacity in t (MW)
p_t	Price in period t subject to cumulative price threshold CPT for prices exceeding administered price p_a

The model presented above is a stylized representation of joint generation/capacity and pricing decisions. The model tries to obtain the generation strategy $X_{i,t}$ and associated pricing strategy p_t for all generators that would ensure that these strategies form the CNE. A careful analysis of problem (6)-(10) is critical to understand the implications of the intertemporal generation and pricing issues. To this end, we analyse the pricing implications as discussed below.

We form the Lagrangian Ψ of the optimization problem and differentiate it with respect to $X_{i,t}$ and capacity $\Phi_{i,t}$ to obtain the following optimality conditions:

78 (Short run) Marginal cost (SRMC) of generation may vary within a year due to variation in variable O&M and seasonal heat rate, etc although we do not have data on seasonal marginal costs for the NEM and as such this has not been modelled.

$$\frac{\partial \Psi}{\partial X_{i,t}} = \alpha_t - 2\beta_t X_{i,t} - \beta_t \sum_{j \neq i} X_{j,t} - C_{i,t} + \lambda_{i,t} + \mu = 0 \forall (i,t) \tag{11}$$

$$\frac{\partial \Psi}{\partial \phi_{i,t}} = -\lambda_{i,t} X_{i,t}^{Max} + \theta_i + \mu = 0 \forall i \tag{12}$$

where,

$\lambda_{i,t}$	duals associated with capacity constraint (8)
θ_i	duals associated with intertemporal constraint (9), and
μ	dual of CPT limit (10).

Optimality condition (11) above presents the well known result of a capacity constrained Cournot Nash problem. $\lambda_{i,t}$ is simply the marginal value of capacity limit and if this limit is not binding, such marginal values reduce to zero. However, the addition of intertemporal pricing decisions has the implication that generation can now be traded across different time periods to achieve different price outcomes without breaching the CPT. θ_i represents the marginal value of an increment in availability (or, reduction in outage) that is achieved by optimally distributing such available generation *across all periods*. We also note that,

$$\lambda_{i,t} = \theta_i / X_{i,t}^{Max} + \mu \tag{13}$$

Equation (13) comprehensively represents the intertemporal effect of CPT namely the shadow price of CPT, marginal value of generation and marginal value of capacity across all periods *t* should be equal. Intuitively, this relationship reveals that a binding CPT limit (i.e., positive value of μ) will lead to a price increase that is not necessarily limited to the highest price period but *across all periods*. A more subtle issue to be noted here is that $\lambda_{i,t}$ for generator *i* is also dependent on the generation and capacity withdrawal strategies of other generators ($j \neq i$) as per (11).

APPENDIX D KEY MODELLING ASSUMPTIONS

This section describes the NEM modelling assumptions used in the analysis. The study focuses on two representative weeks in 2007 and 2008 in order to gain a detailed understanding of the factors that played a material role in shaping market events.

D.1. DEMAND

Half-hourly demand data used for the study is shown in Table D1.

Table D1 Half-Hourly Demand Data Used for the Study

Period	March 11-17, 2008						June 12-18, 2007					
	SA	NSW	QLD	SNY	TAS	VIC	SA	NSW	QLD	SNY	TAS	VIC
1	1,718	7,977	5,418	69	971	5,295	1,647	8,799	5,157	29	1,151	5,539
2	1,637	7,745	5,247	70	978	5,099	1,610	8,640	4,985	39	1,109	5,415
3	1,569	7,500	5,038	69	994	4,945	1,614	8,435	4,887	31	1,108	5,296
4	1,457	7,211	4,890	66	1,009	5,348	1,528	8,332	4,777	33	1,107	5,649
5	1,360	6,921	4,775	67	997	5,169	1,429	8,081	4,655	33	1,095	5,580
6	1,310	6,729	4,698	72	994	4,946	1,364	7,762	4,499	29	1,102	5,358
7	1,282	6,684	4,612	72	1,013	4,815	1,272	7,440	4,454	35	1,108	5,219
8	1,287	6,678	4,594	70	1,022	4,758	1,268	7,217	4,407	36	1,117	5,073
9	1,268	6,710	4,627	68	1,024	4,730	1,215	7,114	4,399	29	1,132	4,959
10	1,303	6,991	4,619	72	1,039	4,866	1,211	7,079	4,461	28	1,132	4,916
11	1,363	7,261	4,733	61	1,059	5,025	1,179	7,145	4,561	35	1,133	4,904
12	1,425	7,903	4,920	71	1,109	5,434	1,186	7,457	4,793	35	1,151	4,998
13	1,497	8,561	5,134	50	1,178	5,848	1,254	7,961	5,077	33	1,183	5,224
14	1,582	8,928	5,573	47	1,246	6,306	1,288	8,838	5,623	28	1,250	5,672
15	1,729	9,312	5,987	43	1,308	6,617	1,414	9,735	6,083	38	1,373	6,153
16	1,804	9,489	6,334	46	1,319	6,549	1,590	10,303	6,540	45	1,475	6,478
17	1,861	9,679	6,548	49	1,290	6,585	1,748	10,815	6,680	52	1,565	6,838
18	1,954	9,982	6,684	48	1,245	6,726	1,843	10,908	6,565	35	1,613	6,982
19	2,058	10,153	6,758	52	1,240	6,730	1,880	10,769	6,417	45	1,585	6,984
20	2,165	10,269	6,837	56	1,243	6,778	1,887	10,715	6,334	47	1,559	7,079
21	2,231	10,429	6,872	48	1,243	6,848	1,913	10,586	6,317	39	1,531	7,054
22	2,255	10,482	6,952	49	1,235	6,895	1,893	10,511	6,255	37	1,468	7,001
23	2,326	10,614	6,947	53	1,224	6,908	1,875	10,349	6,205	30	1,413	6,979
24	2,404	10,659	6,988	44	1,224	7,080	1,849	10,175	6,153	41	1,384	6,922
25	2,447	10,717	6,983	56	1,219	7,105	1,853	10,065	6,107	34	1,380	6,911
26	2,519	10,842	6,964	62	1,188	7,137	1,851	10,008	6,075	30	1,371	6,900
27	2,571	10,911	6,982	54	1,185	7,149	1,848	10,000	6,068	30	1,337	6,884
28	2,604	10,994	6,987	49	1,195	7,196	1,825	9,942	6,066	34	1,285	7,032
29	2,676	11,043	7,027	22	1,196	7,215	1,848	9,883	6,047	27	1,121	7,045
30	2,685	11,077	7,039	42	1,200	7,226	1,858	9,834	6,044	41	1,338	7,014
31	2,684	11,152	7,003	38	1,195	7,195	1,832	9,860	6,029	29	1,359	6,971
32	2,712	11,239	6,996	40	1,198	7,237	1,832	9,929	6,018	38	1,374	6,950
33	2,748	11,225	6,983	46	1,204	7,270	1,810	10,145	6,048	34	1,400	6,972
34	2,774	11,100	6,995	42	1,198	7,197	1,807	10,414	6,160	42	1,450	7,024
35	2,756	10,891	6,973	39	1,196	7,087	1,852	10,973	6,308	33	1,482	7,199
36	2,720	10,527	6,897	52	1,218	6,828	1,928	11,838	6,634	38	1,538	7,425
37	2,611	10,325	6,840	59	1,205	6,623	2,096	12,413	6,962	39	1,566	7,638

Period	March 11-17, 2008						June 12-18, 2007					
	SA	NSW	QLD	SNY	TAS	VIC	SA	NSW	QLD	SNY	TAS	VIC
38	2,570	10,108	6,759	37	1,216	6,417	2,198	12,400	6,833	37	1,548	7,448
39	2,466	10,188	6,902	25	1,228	6,372	2,258	12,346	6,677	25	1,543	7,267
40	2,392	10,010	6,793	38	1,256	6,460	2,209	12,104	6,574	28	1,512	7,171
41	2,350	9,814	6,620	37	1,239	6,358	2,148	11,963	6,518	37	1,488	7,088
42	2,252	9,394	6,551	37	1,225	6,200	2,122	11,791	6,392	42	1,477	6,986
43	2,191	9,017	6,421	35	1,204	5,996	2,037	11,565	6,250	49	1,449	6,845
44	2,048	9,008	6,380	39	1,191	5,742	2,022	11,248	6,278	30	1,429	6,639
45	1,935	8,768	6,157	36	1,160	5,465	1,930	10,636	6,093	43	1,392	6,388
46	1,812	8,641	5,904	26	1,125	5,312	1,839	10,558	5,882	38	1,317	6,086
47	1,736	8,457	5,752	34	1,097	5,246	1,756	10,076	5,713	43	1,243	5,851
48	1,681	8,250	5,638	41	1,084	5,553	1,691	9,872	5,558	25	1,187	6,133
49	1,788	8,065	5,408	41	1,069	5,431	1,767	9,595	5,308	36	1,147	5,951
50	1,693	7,832	5,195	44	1,060	5,203	1,746	9,421	5,105	25	1,139	5,806
51	1,624	7,626	5,023	48	1,043	5,096	1,691	9,236	4,923	25	1,115	5,647
52	1,522	7,286	4,886	39	1,032	5,447	1,602	9,051	4,808	36	1,109	6,022
53	1,449	6,974	4,736	42	1,017	5,249	1,478	8,813	4,681	30	1,095	5,853
54	1,355	6,755	4,662	43	1,012	5,029	1,373	8,422	4,583	39	1,086	5,676
55	1,325	6,646	4,641	39	1,022	4,861	1,320	8,057	4,524	35	1,079	5,495
56	1,314	6,640	4,620	35	1,030	4,810	1,273	7,697	4,540	46	1,088	5,366
57	1,344	6,687	4,634	37	1,046	4,791	1,221	7,573	4,469	28	1,085	5,219
58	1,351	6,955	4,664	44	1,054	4,959	1,216	7,518	4,518	38	1,100	5,149
59	1,381	7,264	4,715	38	1,071	5,103	1,222	7,603	4,629	35	1,115	5,177
60	1,453	7,925	4,952	37	1,129	5,488	1,262	7,939	4,807	23	1,131	5,258
61	1,552	8,580	5,136	40	1,188	5,895	1,285	8,416	5,153	23	1,181	5,433
62	1,659	8,916	5,522	39	1,264	6,342	1,347	9,368	5,672	30	1,232	5,868
63	1,799	9,314	5,963	40	1,294	6,577	1,487	10,401	6,117	27	1,321	6,317
64	1,884	9,476	6,355	42	1,278	6,469	1,651	10,988	6,592	45	1,443	6,677
65	1,926	9,678	6,548	30	1,258	6,446	1,787	11,498	6,716	52	1,525	6,991
66	2,012	9,973	6,724	40	1,246	6,617	1,877	11,548	6,612	49	1,567	7,121
67	2,104	10,135	6,740	47	1,220	6,633	1,918	11,323	6,477	53	1,546	7,117
68	2,230	10,272	6,800	39	1,203	6,633	1,928	11,246	6,396	45	1,532	7,147
69	2,321	10,393	6,833	37	1,205	6,750	1,912	11,089	6,281	53	1,496	7,112
70	2,410	10,395	6,845	56	1,199	6,822	1,896	10,944	6,178	48	1,424	7,037
71	2,449	10,492	6,827	49	1,190	6,942	1,866	10,777	6,121	42	1,404	7,016
72	2,493	10,590	6,813	44	1,173	7,020	1,845	10,552	6,083	23	1,385	7,006
73	2,556	10,622	6,851	39	1,161	7,028	1,849	10,392	6,068	36	1,359	6,985
74	2,619	10,696	6,837	53	1,161	7,085	1,862	10,282	6,007	49	1,339	6,943
75	2,696	10,778	6,832	57	1,158	7,162	1,851	10,149	5,955	49	1,364	6,913
76	2,739	10,899	6,855	40	1,160	7,232	1,844	10,074	5,918	44	1,353	7,018
77	2,796	10,974	6,860	47	1,192	7,311	1,866	10,003	5,873	44	1,216	7,000
78	2,818	11,007	6,890	42	1,219	7,329	1,863	9,959	5,897	38	1,269	6,998
79	2,837	11,094	6,889	46	1,224	7,367	1,846	9,878	5,920	38	1,361	6,990
80	2,884	11,182	6,859	42	1,230	7,389	1,816	9,900	5,968	49	1,307	6,719
81	2,916	11,192	6,874	45	1,243	7,379	1,826	10,141	6,019	32	1,380	6,928
82	2,902	10,949	6,850	40	1,258	7,324	1,858	10,526	6,135	50	1,428	7,001
83	2,862	10,868	6,846	34	1,264	7,197	1,895	11,155	6,389	51	1,465	7,120
84	2,816	10,451	6,743	37	1,255	6,978	1,976	12,058	6,805	37	1,554	7,466
85	2,770	10,282	6,709	33	1,258	6,781	2,098	12,665	7,088	48	1,566	7,763
86	2,711	10,036	6,702	42	1,243	6,572	2,232	12,650	6,958	41	1,551	7,742
87	2,630	10,130	6,873	35	1,249	6,496	2,226	12,548	6,846	29	1,533	7,584

Period	March 11-17, 2008						June 12-18, 2007					
	SA	NSW	QLD	SNY	TAS	VIC	SA	NSW	QLD	SNY	TAS	VIC
88	2,566	10,055	6,762	47	1,286	6,625	2,182	12,303	6,709	30	1,524	7,390
89	2,557	9,763	6,578	38	1,267	6,569	2,102	12,127	6,594	33	1,517	7,251
90	2,461	9,378	6,444	42	1,247	6,336	2,100	12,007	6,475	25	1,513	7,132
91	2,370	9,044	6,326	39	1,220	6,134	2,021	11,729	6,389	43	1,487	7,003
92	2,249	8,954	6,252	34	1,196	5,906	1,953	11,400	6,444	48	1,464	6,785
93	2,120	8,734	6,017	44	1,179	5,664	1,905	10,971	6,183	45	1,422	6,590
94	1,992	8,608	5,847	46	1,148	5,462	1,867	10,807	5,968	41	1,375	6,280
95	1,920	8,348	5,664	44	1,116	5,314	1,800	10,384	5,761	37	1,309	6,053
96	1,841	8,169	5,569	73	1,091	5,660	1,722	10,117	5,600	31	1,249	6,271
97	1,954	7,953	5,391	85	1,074	5,516	1,806	9,834	5,381	27	1,186	6,143
98	1,853	7,738	5,169	114	1,064	5,294	1,732	9,640	5,194	22	1,147	6,019
99	1,782	7,511	5,005	111	1,063	5,159	1,692	9,389	5,112	26	1,135	5,876
100	1,659	7,226	4,877	107	1,051	5,544	1,593	9,216	4,907	34	1,147	6,179
101	1,597	6,942	4,739	109	1,044	5,361	1,499	8,948	4,742	41	1,153	6,033
102	1,558	6,754	4,657	103	1,032	5,106	1,407	8,498	4,616	35	1,145	5,832
103	1,523	6,677	4,646	109	1,025	4,941	1,338	8,137	4,549	37	1,115	5,694
104	1,517	6,711	4,651	110	1,025	4,872	1,294	7,847	4,532	40	1,126	5,563
105	1,492	6,800	4,649	104	1,023	4,898	1,241	7,699	4,501	29	1,129	5,397
106	1,479	7,020	4,701	106	1,036	4,998	1,216	7,603	4,528	38	1,141	5,291
107	1,512	7,344	4,792	108	1,050	5,196	1,227	7,702	4,630	34	1,166	5,379
108	1,509	8,006	5,002	104	1,099	5,569	1,228	8,045	4,915	27	1,198	5,493
109	1,608	8,643	5,241	67	1,183	5,918	1,260	8,529	5,268	30	1,233	5,729
110	1,707	9,003	5,601	43	1,273	6,385	1,350	9,532	5,741	40	1,298	6,183
111	1,815	9,389	6,019	53	1,296	6,639	1,505	10,515	6,239	49	1,383	6,686
112	1,903	9,693	6,361	70	1,267	6,539	1,682	11,178	6,777	37	1,503	7,019
113	1,976	9,795	6,573	53	1,245	6,563	1,836	11,722	6,916	48	1,592	7,303
114	2,102	10,177	6,699	44	1,224	6,675	1,974	11,782	6,818	49	1,642	7,494
115	2,252	10,355	6,721	41	1,172	6,824	2,038	11,550	6,611	46	1,623	7,507
116	2,330	10,528	6,810	42	1,124	6,943	2,030	11,478	6,579	38	1,587	7,520
117	2,420	10,676	6,823	42	1,127	7,121	2,032	11,342	6,445	51	1,582	7,483
118	2,485	10,697	6,838	44	1,126	7,294	1,984	11,242	6,391	35	1,546	7,369
119	2,571	10,847	6,885	52	1,152	7,427	1,952	11,076	6,350	36	1,486	7,281
120	2,640	10,953	6,929	44	1,158	7,544	1,912	10,922	6,312	35	1,462	7,187
121	2,703	11,051	6,948	49	1,156	7,700	1,894	10,810	6,270	25	1,461	7,112
122	2,745	11,119	6,945	45	1,159	7,863	1,892	10,791	6,197	33	1,434	7,063
123	2,821	11,191	6,994	50	1,158	8,038	1,866	10,699	6,140	32	1,396	7,018
124	2,878	11,262	7,021	33	1,159	8,161	1,864	10,664	6,076	42	1,360	7,109
125	2,927	11,164	7,056	43	1,171	8,345	1,863	10,709	6,085	36	1,355	7,044
126	2,863	11,219	7,071	46	1,181	8,425	1,849	10,717	6,046	46	1,384	7,045
127	2,830	11,312	7,045	29	1,185	8,553	1,832	10,770	6,023	31	1,371	6,997
128	2,871	11,290	7,042	34	1,145	8,739	1,809	10,835	6,083	27	1,379	6,941
129	2,891	11,260	7,023	24	1,185	8,889	1,806	11,122	6,124	33	1,392	6,911
130	2,921	11,101	7,002	39	1,217	8,872	1,817	11,461	6,213	30	1,434	6,908
131	2,913	11,043	6,952	31	1,232	8,884	1,873	11,904	6,486	47	1,508	7,007
132	2,891	10,733	6,859	32	1,206	8,698	1,920	12,360	6,894	47	1,595	7,375
133	2,885	10,558	6,870	23	1,177	8,473	2,107	12,795	7,147	63	1,628	7,726
134	2,835	10,364	6,874	41	1,160	8,251	2,271	12,760	7,031	45	1,609	7,694
135	2,755	10,479	7,066	29	1,146	8,117	2,312	12,631	6,926	51	1,616	7,508
136	2,756	10,368	6,976	35	1,141	8,139	2,311	12,478	6,799	42	1,581	7,414
137	2,757	10,117	6,749	39	1,149	7,919	2,251	12,358	6,661	36	1,576	7,358

Period	March 11-17, 2008						June 12-18, 2007					
	SA	NSW	QLD	SNY	TAS	VIC	SA	NSW	QLD	SNY	TAS	VIC
138	2,661	9,659	6,651	44	1,140	7,604	2,231	12,251	6,591	52	1,577	7,231
139	2,511	9,240	6,500	43	1,112	7,264	2,195	11,935	6,496	52	1,529	7,134
140	2,405	9,144	6,413	49	1,092	6,867	2,151	11,410	6,405	59	1,495	6,902
141	2,252	8,917	6,109	45	1,064	6,463	2,070	10,942	6,143	43	1,441	6,650
142	2,089	8,812	5,910	48	1,031	6,170	2,007	10,804	5,979	30	1,397	6,371
143	1,979	8,539	5,769	50	1,004	5,939	1,928	10,330	5,772	30	1,360	6,142
144	1,896	8,323	5,666	48	986	6,154	1,820	10,070	5,647	19	1,292	6,376
145	1,971	8,088	5,436	96	980	5,934	1,878	9,791	5,408	28	1,234	6,175
146	1,885	7,893	5,242	115	968	5,652	1,825	9,568	5,199	30	1,201	6,012
147	1,793	7,642	5,085	120	964	5,516	1,803	9,329	5,051	23	1,172	5,826
148	1,679	7,280	4,907	124	946	5,891	1,696	9,155	4,890	30	1,143	6,204
149	1,591	7,033	4,765	123	954	5,653	1,586	8,894	4,771	42	1,140	6,006
150	1,535	6,859	4,706	118	957	5,370	1,498	8,463	4,623	32	1,139	5,806
151	1,505	6,801	4,657	117	956	5,249	1,420	8,084	4,530	39	1,131	5,668
152	1,493	6,744	4,653	120	959	5,201	1,373	7,826	4,445	35	1,111	5,535
153	1,517	6,799	4,670	121	965	5,198	1,326	7,634	4,527	37	1,098	5,422
154	1,522	6,983	4,687	120	970	5,332	1,312	7,603	4,573	31	1,129	5,377
155	1,541	7,335	4,746	117	978	5,526	1,311	7,629	4,651	33	1,141	5,396
156	1,579	7,957	4,972	115	1,028	5,903	1,326	7,926	4,908	32	1,160	5,494
157	1,685	8,588	5,156	59	1,092	6,320	1,384	8,366	5,183	33	1,207	5,699
158	1,789	8,977	5,544	36	1,165	6,815	1,460	9,299	5,673	21	1,283	6,147
159	1,934	9,385	5,979	42	1,219	7,091	1,606	10,169	6,082	35	1,357	6,624
160	2,019	9,570	6,355	36	1,224	7,119	1,765	10,754	6,513	47	1,452	6,929
161	2,119	9,794	6,568	30	1,208	7,322	1,927	11,257	6,624	44	1,539	7,313
162	2,204	10,073	6,682	43	1,190	7,603	2,040	11,356	6,567	38	1,559	7,462
163	2,344	10,260	6,767	25	1,176	7,829	2,102	11,221	6,414	46	1,580	7,475
164	2,422	10,407	6,855	32	1,154	8,075	2,114	11,352	6,327	42	1,570	7,581
165	2,445	10,471	6,894	52	1,138	8,274	2,119	11,227	6,265	37	1,544	7,531
166	2,520	10,545	6,962	46	1,150	8,480	2,089	11,250	6,239	31	1,507	7,446
167	2,610	10,666	7,011	46	1,202	8,626	2,060	11,199	6,188	24	1,484	7,387
168	2,698	10,830	6,931	49	1,203	8,783	2,011	11,029	6,159	35	1,406	7,248
169	2,752	10,847	6,936	37	1,210	8,840	1,976	10,962	6,146	12	1,438	7,280
170	2,769	10,791	6,946	43	1,222	9,060	1,941	10,902	6,107	21	1,436	7,173
171	2,814	10,971	6,950	44	1,201	9,144	1,895	10,857	6,059	37	1,417	7,094
172	2,790	11,121	6,932	64	1,187	9,224	1,879	10,864	6,026	35	1,392	7,126
173	2,832	11,163	6,954	53	1,187	9,258	1,886	10,782	6,017	38	1,364	7,019
174	2,837	11,136	6,943	42	1,211	9,271	1,863	10,815	6,056	18	1,374	6,902
175	2,866	11,315	6,975	30	1,203	9,314	1,844	10,768	6,034	39	1,397	6,786
176	2,896	11,447	6,917	48	1,215	9,390	1,813	10,876	5,992	28	1,390	6,706
177	2,934	11,423	6,932	71	1,234	9,375	1,807	11,151	6,042	30	1,396	6,682
178	2,914	11,240	6,898	58	1,218	9,274	1,822	11,505	6,117	32	1,461	6,696
179	2,862	11,034	6,916	48	1,219	9,189	1,870	11,853	6,196	31	1,499	6,877
180	2,758	10,630	6,869	40	1,228	8,906	1,969	12,268	6,515	27	1,546	7,193
181	2,661	10,373	6,711	59	1,178	8,525	2,139	12,527	6,729	31	1,533	7,588
182	2,587	10,102	6,621	45	1,132	8,064	2,274	12,386	6,594	28	1,535	7,571
183	2,477	10,137	6,782	34	1,126	7,773	2,313	12,173	6,462	29	1,512	7,444
184	2,423	9,908	6,667	51	1,154	7,697	2,281	11,954	6,360	32	1,497	7,211
185	2,372	9,653	6,534	46	1,137	7,464	2,222	11,719	6,306	31	1,468	7,158
186	2,292	9,331	6,462	42	1,119	7,104	2,212	11,534	6,200	26	1,455	7,010
187	2,212	8,950	6,328	38	1,097	6,741	2,171	11,258	6,133	39	1,428	6,900

Period	March 11-17, 2008						June 12-18, 2007					
	SA	NSW	QLD	SNY	TAS	VIC	SA	NSW	QLD	SNY	TAS	VIC
188	2,132	9,014	6,360	57	1,087	6,451	2,128	10,974	6,163	58	1,411	6,693
189	2,020	8,869	6,140	42	1,081	6,193	2,083	10,682	6,000	38	1,374	6,521
190	1,895	8,835	5,982	41	1,056	5,944	2,046	10,687	5,850	38	1,320	6,384
191	1,801	8,600	5,904	48	1,031	5,783	1,977	10,424	5,742	37	1,259	6,200
192	1,738	8,404	5,780	46	1,021	6,019	1,910	10,186	5,614	33	1,225	6,503
193	1,836	8,102	5,539	44	1,015	5,776	1,977	9,914	5,438	40	1,200	6,287
194	1,717	7,827	5,311	61	1,011	5,490	1,894	9,650	5,202	34	1,169	6,079
195	1,640	7,556	5,139	92	1,010	5,358	1,844	9,384	5,055	27	1,138	5,905
196	1,528	7,177	4,964	119	1,005	5,705	1,725	9,110	4,808	40	1,114	6,188
197	1,448	6,915	4,791	121	1,003	5,404	1,616	8,768	4,645	29	1,100	5,992
198	1,418	6,739	4,689	119	1,001	5,173	1,500	8,387	4,539	31	1,090	5,736
199	1,383	6,637	4,649	117	1,004	4,982	1,426	7,986	4,540	34	1,092	5,544
200	1,360	6,511	4,653	116	1,022	4,950	1,376	7,671	4,508	36	1,100	5,415
201	1,364	6,523	4,666	121	1,023	4,905	1,345	7,437	4,515	38	1,100	5,258
202	1,363	6,636	4,709	116	1,024	4,923	1,314	7,336	4,547	33	1,083	5,194
203	1,368	6,725	4,707	114	1,025	5,003	1,298	7,320	4,605	34	1,073	5,155
204	1,357	6,990	4,806	114	1,038	5,114	1,301	7,422	4,698	50	1,091	5,150
205	1,388	7,181	4,896	110	1,068	5,243	1,326	7,567	4,820	42	1,110	5,218
206	1,431	7,441	5,036	117	1,082	5,439	1,373	7,891	5,062	32	1,131	5,355
207	1,466	7,858	5,233	123	1,116	5,546	1,420	8,273	5,287	32	1,155	5,484
208	1,496	8,230	5,536	63	1,141	5,642	1,481	8,711	5,644	44	1,199	5,572
209	1,544	8,608	5,784	44	1,160	5,798	1,547	9,387	5,884	40	1,257	5,821
210	1,669	9,086	6,021	49	1,171	6,005	1,650	9,938	6,136	42	1,366	6,097
211	1,763	9,230	6,245	46	1,175	6,106	1,787	10,371	6,115	40	1,449	6,278
212	1,862	9,421	6,300	41	1,179	6,236	1,853	10,743	6,105	48	1,480	6,436
213	1,958	9,424	6,369	40	1,162	6,356	1,885	10,701	6,093	34	1,456	6,437
214	1,999	9,514	6,346	48	1,158	6,426	1,871	10,678	5,978	44	1,440	6,437
215	2,064	9,562	6,285	46	1,144	6,526	1,815	10,584	5,892	37	1,408	6,391
216	2,125	9,605	6,243	46	1,159	6,588	1,748	10,416	5,818	34	1,398	6,345
217	2,180	9,703	6,223	52	1,159	6,668	1,724	10,212	5,702	37	1,361	6,329
218	2,224	9,790	6,194	50	1,135	6,732	1,701	10,151	5,656	40	1,330	6,219
219	2,294	9,849	6,163	50	1,115	6,859	1,678	10,088	5,590	39	1,306	6,119
220	2,354	9,904	6,173	48	1,118	6,976	1,686	9,873	5,546	43	1,290	6,113
221	2,400	9,976	6,120	48	1,121	7,058	1,690	9,748	5,500	38	1,287	6,093
222	2,407	10,003	6,136	48	1,116	7,148	1,664	9,692	5,492	30	1,313	6,047
223	2,432	10,130	6,103	41	1,105	7,205	1,626	9,629	5,486	33	1,319	5,966
224	2,463	10,159	6,120	45	1,097	7,163	1,631	9,617	5,478	38	1,289	5,943
225	2,474	10,165	6,124	44	1,110	7,363	1,637	9,811	5,505	34	1,323	5,984
226	2,489	10,016	6,123	48	1,117	7,366	1,675	10,132	5,614	38	1,360	6,009
227	2,500	9,960	6,168	52	1,136	7,349	1,736	10,572	5,832	41	1,415	6,176
228	2,474	9,786	6,139	54	1,131	7,218	1,883	11,044	6,302	33	1,486	6,528
229	2,417	9,593	6,177	57	1,122	7,010	2,062	11,379	6,669	50	1,510	6,704
230	2,341	9,460	6,231	48	1,112	6,813	2,132	11,295	6,596	51	1,486	6,645
231	2,296	9,492	6,413	42	1,122	6,768	2,141	11,119	6,454	46	1,471	6,656
232	2,253	9,365	6,310	47	1,134	6,736	2,079	10,842	6,298	41	1,428	6,551
233	2,235	9,135	6,189	43	1,129	6,643	2,015	10,600	6,263	33	1,395	6,428
234	2,169	8,869	5,944	47	1,115	6,444	1,949	10,401	6,126	27	1,423	6,324
235	2,086	8,653	5,802	53	1,096	6,314	1,914	10,217	6,097	31	1,423	6,250
236	2,020	8,603	5,775	54	1,080	6,110	1,872	9,985	6,136	44	1,377	6,136
237	1,937	8,396	5,629	57	1,027	5,896	1,822	9,777	5,890	38	1,343	5,962

Period	March 11-17, 2008						June 12-18, 2007					
	SA	NSW	QLD	SNY	TAS	VIC	SA	NSW	QLD	SNY	TAS	VIC
238	1,866	8,280	5,547	79	1,030	5,749	1,781	9,692	5,712	36	1,285	5,847
239	1,828	8,037	5,553	81	1,018	5,597	1,756	9,533	5,671	26	1,231	5,748
240	1,788	7,760	5,511	83	1,002	5,771	1,714	9,406	5,618	38	1,183	5,944
241	1,883	7,586	5,342	78	981	5,545	1,839	9,066	5,388	39	1,145	5,837
242	1,805	7,369	5,148	90	984	5,305	1,771	8,779	5,214	30	1,117	5,673
243	1,723	7,212	5,016	119	979	5,154	1,743	8,469	5,075	26	1,074	5,531
244	1,599	6,875	4,892	120	972	5,512	1,658	8,184	4,932	41	1,071	5,900
245	1,465	6,631	4,767	126	966	5,272	1,523	7,900	4,812	38	1,053	5,694
246	1,415	6,507	4,620	121	956	5,020	1,440	7,552	4,673	38	1,039	5,455
247	1,363	6,427	4,523	114	957	4,857	1,368	7,303	4,595	39	1,028	5,259
248	1,317	6,375	4,553	115	954	4,734	1,296	7,083	4,543	48	1,039	5,156
249	1,306	6,350	4,552	120	961	4,700	1,244	6,978	4,498	43	1,023	5,031
250	1,307	6,433	4,607	115	926	4,685	1,215	6,929	4,531	35	1,038	4,912
251	1,322	6,468	4,606	107	936	4,711	1,185	6,936	4,516	35	1,056	4,846
252	1,318	6,655	4,677	116	960	4,765	1,163	6,983	4,577	37	1,060	4,817
253	1,316	6,752	4,718	113	968	4,839	1,195	7,118	4,688	33	1,075	4,832
254	1,323	6,930	4,763	117	981	4,943	1,195	7,293	4,839	32	1,094	4,874
255	1,303	7,206	4,890	113	1,010	4,992	1,232	7,550	4,974	33	1,112	4,953
256	1,385	7,615	5,085	115	1,046	5,092	1,249	7,881	5,244	49	1,148	4,934
257	1,443	7,908	5,342	118	1,057	5,270	1,296	8,436	5,468	46	1,173	5,075
258	1,558	8,324	5,507	93	1,101	5,527	1,356	8,996	5,698	42	1,231	5,309
259	1,680	8,538	5,701	44	1,115	5,757	1,442	9,379	5,806	49	1,300	5,492
260	1,826	8,787	5,788	39	1,111	6,005	1,530	9,731	5,807	55	1,350	5,625
261	1,958	8,850	5,884	41	1,118	6,267	1,564	9,843	5,732	45	1,364	5,707
262	2,097	8,955	5,962	36	1,100	6,484	1,586	9,967	5,711	42	1,367	5,741
263	2,216	9,016	5,989	41	1,095	6,701	1,569	9,827	5,676	45	1,342	5,760
264	2,318	9,014	5,994	51	1,117	6,910	1,531	9,731	5,637	41	1,305	5,713
265	2,414	9,107	5,993	38	1,125	7,123	1,503	9,580	5,578	41	1,265	5,679
266	2,483	9,119	6,069	49	1,115	7,310	1,482	9,521	5,568	45	1,251	5,665
267	2,517	9,129	6,046	52	1,122	7,450	1,482	9,430	5,519	44	1,234	5,660
268	2,558	9,171	6,031	44	1,130	7,597	1,508	9,321	5,466	41	1,224	5,760
269	2,584	9,269	6,011	49	1,133	7,705	1,525	9,228	5,423	41	1,247	5,743
270	2,598	9,356	5,997	47	1,160	7,847	1,523	9,112	5,373	36	1,263	5,792
271	2,628	9,451	5,965	51	1,163	7,993	1,528	9,042	5,361	34	1,261	5,808
272	2,655	9,500	6,007	46	1,155	8,005	1,523	9,170	5,408	37	1,270	5,874
273	2,624	9,487	6,006	52	1,180	8,050	1,505	9,337	5,415	36	1,276	5,963
274	2,657	9,420	6,049	50	1,187	8,023	1,560	9,670	5,585	39	1,318	6,044
275	2,656	9,393	6,073	52	1,201	8,015	1,627	10,182	5,830	39	1,418	6,277
276	2,612	9,377	6,159	51	1,214	7,904	1,731	10,780	6,396	32	1,521	6,652
277	2,560	9,301	6,259	51	1,204	7,710	1,877	11,206	6,701	49	1,579	6,917
278	2,536	9,275	6,394	51	1,196	7,444	2,002	11,245	6,597	44	1,557	6,927
279	2,457	9,419	6,562	60	1,216	7,331	1,973	11,071	6,519	46	1,539	6,812
280	2,404	9,297	6,453	52	1,234	7,358	1,942	10,867	6,365	38	1,505	6,685
281	2,394	9,130	6,285	51	1,228	7,226	1,914	10,711	6,289	43	1,507	6,568
282	2,328	8,845	6,091	54	1,202	6,966	1,866	10,554	6,239	40	1,505	6,481
283	2,225	8,487	5,965	51	1,155	6,685	1,823	10,333	6,156	38	1,469	6,388
284	2,131	8,364	5,970	49	1,141	6,347	1,772	10,005	6,113	45	1,423	6,195
285	2,030	8,154	5,741	51	1,122	6,003	1,719	9,615	5,829	46	1,365	6,017
286	1,929	7,932	5,555	105	1,080	5,766	1,648	9,415	5,636	31	1,339	5,799
287	1,830	7,740	5,531	117	1,072	5,600	1,586	9,004	5,499	37	1,279	5,570

Period	March 11-17, 2008						June 12-18, 2007					
	SA	NSW	QLD	SNY	TAS	VIC	SA	NSW	QLD	SNY	TAS	VIC
288	1,757	7,580	5,472	117	1,048	5,736	1,504	8,739	5,418	37	1,223	5,731
289	1,867	7,371	5,339	114	1,037	5,568	1,593	8,448	5,207	33	1,191	5,626
290	1,777	7,279	5,130	114	1,034	5,353	1,552	8,206	5,041	45	1,185	5,540
291	1,733	7,146	5,012	114	1,025	5,206	1,544	8,035	4,928	37	1,174	5,432
292	1,643	6,896	4,871	116	997	5,595	1,465	7,825	4,800	42	1,165	5,820
293	1,564	6,684	4,757	119	992	5,395	1,391	7,636	4,704	44	1,142	5,693
294	1,484	6,544	4,662	109	1,010	5,146	1,301	7,382	4,613	40	1,157	5,485
295	1,446	6,523	4,638	107	1,032	4,973	1,253	7,098	4,556	40	1,150	5,379
296	1,437	6,505	4,603	114	1,039	4,960	1,218	6,995	4,525	59	1,150	5,248
297	1,453	6,596	4,617	118	1,029	4,947	1,181	6,850	4,510	72	1,158	5,150
298	1,497	6,852	4,655	114	1,016	5,042	1,160	6,934	4,534	71	1,174	5,139
299	1,532	7,214	4,733	111	1,036	5,245	1,141	7,070	4,630	79	1,192	5,134
300	1,555	7,914	4,998	105	1,089	5,693	1,128	7,404	4,893	68	1,219	5,309
301	1,640	8,551	5,218	103	1,155	6,068	1,186	7,901	5,177	34	1,268	5,516
302	1,747	8,989	5,606	50	1,210	6,576	1,265	8,819	5,625	33	1,353	5,954
303	1,882	9,417	6,003	53	1,252	6,854	1,391	9,650	6,122	47	1,431	6,454
304	1,958	9,679	6,439	42	1,238	6,863	1,553	10,252	6,520	38	1,588	6,808
305	1,987	9,833	6,652	45	1,223	7,066	1,730	10,694	6,773	41	1,677	7,215
306	2,126	10,179	6,729	32	1,232	7,326	1,861	10,808	6,740	48	1,740	7,343
307	2,289	10,311	6,835	42	1,192	7,589	1,854	10,679	6,641	43	1,736	7,406
308	2,409	10,513	6,926	42	1,187	7,791	1,854	10,696	6,668	47	1,710	7,488
309	2,534	10,578	6,944	41	1,181	8,074	1,868	10,664	6,579	42	1,685	7,481
310	2,566	10,498	6,977	50	1,187	8,279	1,829	10,715	6,519	44	1,655	7,402
311	2,611	10,595	6,908	48	1,187	8,467	1,833	10,649	6,490	55	1,627	7,333
312	2,684	10,738	6,887	38	1,182	8,685	1,838	10,616	6,411	36	1,593	7,263
313	2,750	10,625	6,889	50	1,177	8,850	1,785	10,520	6,358	38	1,543	7,193
314	2,828	10,764	6,835	56	1,184	9,024	1,831	10,497	6,313	40	1,518	7,117
315	2,900	10,791	6,835	61	1,218	9,184	1,820	10,482	6,253	49	1,516	7,132
316	2,975	10,904	6,848	81	1,243	9,334	1,840	10,470	6,243	46	1,509	7,176
317	3,021	10,879	6,867	64	1,254	9,416	1,871	10,386	6,233	46	1,506	7,115
318	2,978	10,943	6,880	82	1,243	9,423	1,885	10,420	6,168	42	1,544	6,961
319	2,990	10,958	6,851	55	1,272	9,489	1,896	10,449	6,145	33	1,564	6,983
320	2,996	10,980	6,813	31	1,268	9,584	1,892	10,450	6,122	38	1,553	7,005
321	3,033	10,988	6,813	32	1,268	9,701	1,830	10,725	6,181	39	1,576	7,005
322	3,080	10,849	6,812	35	1,287	9,642	1,869	11,076	6,315	45	1,632	7,088
323	3,038	10,727	6,831	48	1,305	9,455	1,903	11,622	6,474	34	1,690	7,253
324	3,037	10,415	6,873	39	1,284	9,271	1,927	12,217	6,873	41	1,701	7,646
325	2,997	10,281	6,968	34	1,237	9,169	2,103	12,534	7,163	37	1,732	7,981
326	2,928	10,065	6,948	43	1,207	8,835	2,232	12,475	7,032	37	1,724	7,898
327	2,834	10,152	6,970	58	1,210	8,737	2,206	12,323	6,852	43	1,685	7,748
328	2,771	9,978	6,781	58	1,240	8,719	2,163	12,044	6,684	36	1,662	7,564
329	2,691	9,711	6,619	50	1,214	8,488	2,102	11,820	6,565	42	1,619	7,496
330	2,565	9,418	6,486	62	1,182	8,150	2,081	11,639	6,448	33	1,645	7,353
331	2,433	8,991	6,388	61	1,137	7,727	2,039	11,369	6,337	45	1,625	7,139
332	2,335	8,918	6,387	58	1,095	7,284	1,928	10,914	6,323	50	1,582	6,896
333	2,201	8,676	6,136	49	1,071	6,830	1,895	10,441	6,017	54	1,520	6,660
334	2,083	8,568	5,921	45	1,061	6,495	1,789	10,327	5,842	43	1,443	6,353
335	1,939	8,383	5,727	55	1,042	6,235	1,764	9,951	5,665	45	1,369	6,075
336	1,872	8,230	5,666	56	1,023	6,422	1,700	9,703	5,528	34	1,314	6,301

D.2. BIDDING SCENARIO ASSUMPTIONS

A combination of Cournot, Bertrand and perfect competition bidding was used for the analysis to gain insights about the role that generator behaviour plays in setting prices.

A key input parameter that determines bids is the elasticity of demand for which we have relied on NIEIR's average regional estimate of elasticity shown in Table D2. These elasticity values determine the extent to which high spot prices can be mitigated by demand-side responses.

Table D2 Price Elasticity of Demand

	Elasticity
QLD	0.29
NSW	0.37
VIC	0.38
SA	0.32
TAS	0.23

Source: National Institute of Economic and Industry Research, *The own price elasticity of demand for electricity in NEM regions*, Report submitted to NEMMCO, June 2007.

Contractual obligation especially two-way hedges held between generators and retailers forms another critical input to generator bids. Contracts significantly limit the exposure to spot price volatility for both generators and retailers. There is little information available in the public domain that gives generator specific contract levels. As such we have relied on a calibration procedure to determine contract level for different time periods (namely, super-peak, peak, off-peak) that reasonably reproduce actual bidding and price behaviour. In other words, we have used observed bidding patterns and pricing outcomes in the NEM in order to deduce levels of contract cover for broad classes of generators across the NEM regions. These contract covers vary across regions depending on the concentration and demand pattern and, on average, are found to be in the rannge 75 to 85 per cent across all generator types. These figures generally align with those reported in some of the other studies including the IES study (2004), Anderson and Hu (2006) and ACCC (2000).[79]

A linear demand curve has been derived for each region for half-hour period of the week. Calculation of intercept and slope terms of these demand curves take into account actual demand and prices. In order to calibrate the demand function, we assume the actual demand/price pair is one of the points on the demand curve. The slope and intercept terms are estimated using a regression of demand and price. The elasticity of demand forms an input to the calibration to calculate the expected slope given an intercept.

79 Intelligent Energy Systems, *Regional Boundary and Nodal Pricing*, December 2004.

E. Anderson and X. Hu, *Forward Contracts in Electricity Markets: The Australian Experience*, Centre for Energy and Environment Studies, May 2006.

ACCC, *VoLL Capacity Mechanisms and Price Floor*, December 2000.

Bertrand and Cournot models use different forms of demand curve, but both essentially model demand as a function of price. Each generator maximises its profit assuming a downward sloping demand curve and adjusts either generation quantity (in Cournot) or bid price (in Bertrand) to achieve an equilibrium profit maximising solution. The derivation of demand parameters and the choice of Cournot and Bertrand paradigms are well documented in the academic literature.[80] A change in VoLL setting (e.g., increasing it from $10,000/MWh to $12,500/MWh) will impact on the demand function parameters. In particular, revised parameters are derived by scaling the parameters estimated using an underlying VoLL setting of $10,000/MWh.

Finally, generator direct operating costs are obtained from the latest ACIL Tasman report prepared for the NEMMCO and presented along with other generator data in Table D3.

D.3. SCENARIO ASSUMPTIONS

In line with the principal objective of the analysis, we have compared and contrasted the price and net revenue outcomes across the following scenarios:

- VoLL $10,000/MWh and CPT $150,000, i.e., a business-as-usual scenario,
- VoLL $10,000/MWh and CPT $187,500, i.e., only CPT is raised,
- VoLL $12,500/MWh and CPT $150,000, i.e., only VoLL is raised, and
- VoLL $12,500/MWh and CPT $187,500, i.e., both VoLL and CPT are raised.

Uncertainties in the following parameters have been used as part of the Monte Carlo simulation studies for each of the four scenarios:

- The generator forced outage rates shown in Table D3 are used to model individual generating unit full outages;
- Peak period demand forecast errors (12 hours ahead) up to 5 per cent on either side of the actual demand is simulated;[81]
- Hydro energy limits are restricted to within a band of -10 per cent and + 20 per cent of the actual dispatch based on the available long term generation potential data;[82]

80 See for example, James Bushnell, *Oligopoly Equilibria in Electricity* Markets, Centre for Study of Energy *Markets,* CSEM WP 148-R, October 2006. for a discussion on Cournot model. An example of a price competition model is in: *Richard* Green, *Did English Generators Play Cournot? Capacity withholding in the electricity pool"* Cambridge Working Paper, CWPE 0425, 2004.

81 Actual demand forecast errors for the two weeks varied and were both higher and lower than 5 per cent, e.g., NSW demand forecast errors were up to 7 per cent on one occasion in June 2007. An average symmetric error of 5 per cent is generally representative of the forecast errors. The Mean Absolute Percentage Error (MAPE) performance of NEMMCO's load forecasting tool has been reported to have a much better accuracy below 1 per cent but this has been derived using testing over a wider timeframe and presumably for less volatile demand conditions.

82 Based on a number of sources including:

- the long term average capacity factor presented in, NSW Greenhouse Benchmarks Position Paper, Ministry of Energy and Utilities, December 2001.
- Individual hydro station outputs over 1999-2008 (April)
- Hydro Tasmania storage level.

- Interconnector outage rates are typically much lower than those for generators. They have generally been excluded for NEM simulation studies including the ANTS. However, given the potential large impact they may have on spot prices they have been modelled as a low probability event in the range of 0.1-0.2 per cent;[83]

- Gas curtailment has been modelled as 1-in-20 year events as noted in VENCORP planning documents and used for modelling simulations.[84]

D.4. GENERATOR DATA

Table D3 lists the data on NEM power stations used in the modelling study.

Table D3 Generator Data

	Region	Intra-Regional Loss Factor	Capacity (MW)	Auxiliary Consumption (%)	Forced Outage Rate (%)	Planned Outage Rate (%)	Direct Operating Cost *($/MWh)
Barcaldine	1	0.9473	49	3%	5%	8%	48.29
Barron Gorge	1	1.0695	60	0%	4%	5%	-
Braemar	1	0.9629	450	3%	10%	2%	24.17
Callide A	1	0.9085	-	7%	4%	4%	-
Callide B	1	0.9115	700	7%	4%	4%	13.69
Callide C (CPP)	1	0.9097	920	7%	4%	4%	12.76
Collinsville	1	1.0253	187	9%	4%	4%	21.60
Gladstone	1	0.9428	1,680	5%	4%	4%	15.45
Kareeya	1	1.0808	88	0%	4%	5%	-
Kogan Creek	1	0.9629	763	8%	4%	4%	5.92
Mackay GT	1	0.9562	34	3%	10%	2%	330.04
Millmerran	1	0.9725	860	8%	4%	4%	6.07
Mt Stuart	1	1.0367	294	3%	10%	2%	273.32
Oakey	1	0.9483	320	3%	10%	2%	52.15
QLD Wind Projects	1	0.9749	12	0%	2%	5%	
Roma GT	1	0.9582	68	3%	10%	2%	57.47
Stanwell	1	0.9320	1,440	7%	4%	4%	13.63
Swanbank B	1	0.9943	480	8%	4%	4%	20.04
Swanbank E	1	0.9935	370	3%	5%	8%	16.00
Tarong	1	0.9663	1,400	8%	4%	4%	11.85
TNPS1	1	0.9661	443	8%	4%	4%	11.05
Wivenhoe	1	0.9890	500	0%	4%	5%	-
Yabulu	1	1.0131	243	3%	10%	2%	-
Bayswater	2	0.9383	2,760	6%	4%	8%	12.32
Blowering	2	0.9815	80	0%	4%	0%	-
Eraring	2	0.9842	2,640	7%	4%	8%	16.88
Hume (NSW)	2	1.0057	-	0%	4%	0%	-
HVGTS	2	0.9406	51	3%	10%	1%	309.15
Liddell	2	0.9387	2,100	5%	4%	8%	13.02

83 There is limited available information on history of partial/full outage rates applicable for the Australian information. Transgrid has reported an outage rate of 8 hours per 170 km-year for 330 kV lines which is approximately an outage rate of 0.1 per cent and Hydro Tasmania has reported Basslink availability (including planned outages) is reported to be 99.7 per cent.

84 VENCorp, *Major System Augmentation Report for the Victorian Principal Transmission System*, November, 2005.

	Region	Intra-Regional Loss Factor	Capacity (MW)	Auxiliary Consumption (%)	Forced Outage Rate (%)	Planned Outage Rate (%)	Direct Operating Cost *($/MWh)
Mt Piper	2	0.9641	1,400	5%	4%	8%	17.12
Munmorah	2	0.9883	600	2%	4%	8%	18.31
NSW Wind Projects	2	0.9752	17	0%	2%	5%	-
Redbank	2	0.9265	150	8%	4%	8%	12.74
Shoalhaven	2	1.0183	240	0%	4%	0%	-
Smithfield	2	1.0023	160	5%	2%	7%	37.40
Vales Point	2	0.9861	1,320	5%	4%	8%	16.08
Wallerawang	2	0.9643	1,000	7%	4%	8%	19.03
Guthega	6	0.9680	60	0%	4%	4%	-
Murray	6	1.0000	1,500	0%	4%	4%	-
Tumut3	6	1.0009	1,500	0%	4%	4%	-
Upptumut	6	0.9958	616	0%	4%	4%	-
Somerton	4	1.0000	160	3%	10%	1%	45.07
Anglesea	4	1.0173	154	10%	4%	5%	6.06
Bairnsdale	4	0.9691	90	3%	10%	1%	39.84
Dartmouth	4	0.9619	154	0%	4%	4%	-
Eildon	4	0.9934	120	0%	4%	4%	-
Hazelwood	4	0.9673	1,600	10%	4%	5%	2.32
Hume (VIC)	4	1.0000	29	0%	4%	4%	-
Jeeralang A	4	0.9638	232	3%	10%	1%	47.77
Jeeralang B	4	0.9638	255	3%	10%	1%	47.77
Laverton North	4	0.9954	340	3%	10%	1%	50.79
LoyYang A	4	0.9699	2,190	8%	4%	5%	2.12
LoyYang B	4	0.9699	1,032	8%	4%	5%	5.87
McKay	4	0.9738	150	0%	4%	4%	-
Morwell	4	0.9676	148	15%	4%	5%	-
Newport	4	0.9957	510	5%	2%	7%	43.63
Valley Power	4	0.9699	336	3%	10%	1%	54.24
VIC Wind Projects	4	0.9801	134	0%	2%	5%	-
West Kiewa	4	0.9911	72	0%	4%	4%	-
Yallourn	4	0.9529	1,487	9%	4%	5%	2.38
Hallett	3	0.9802	188	3%	10%	1%	58.88
Angaston	3	1.0011	40	8%	10%	1%	273.86
Dry Creek	3	1.0012	140	3%	10%	1%	71.58
Ladbroke	3	0.9589	84	3%	10%	1%	32.76
Mintaro	3	0.9737	88	3%	10%	1%	65.51
Northern	3	0.9706	540	5%	4%	8%	17.71
Osborne	3	0.9998	190	5%	2%	4%	33.32
Playford B	3	0.9710	240	8%	4%	8%	25.55
Port Lincoln	3	1.0226	50	8%	10%	1%	355.30
Pelican Point	3	0.9989	474	2%	5%	4%	32.23
Quarantine	3	0.9959	92	2%	10%	1%	47.74
SA Wind Projects	3	0.9883	388	0%	2%	5%	-
Snuggery	3	0.9636	63	3%	10%	1%	355.50
Torrens A	3	0.9994	504	5%	2%	4%	50.40
Torrens B	3	0.9994	824	5%	2%	4%	46.37
Bell Bay	5	0.9985	228	5%	2%	4%	55.96
Bell Bay Three	5	0.9976	108	3%	10%	1%	60.97
Tasmania Hydro	5	0.9777	2,281	0%	4%	5%	-

	Region	Intra-Regional Loss Factor	Capacity (MW)	Auxiliary Consumption (%)	Forced Outage Rate (%)	Planned Outage Rate (%)	Direct Operating Cost *($/MWh)
Tasmania Wind Projects	5	0.9913	142	0%	2%	5%	-

Notes: *ACIL Tasman estimates of Short Run Marginal Costs that include direct operating costs including fuel and O&M costs. ACIL Tasman, *Fuel Resource, New Entry and Generation Costs in the NEM*, Final Report, September 2007.