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Draft Report to

AEMC

Reliability Standard and Settings Review

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Version History

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EXECUTIVE SUMMARY

The Reliability Panel is required to conduct a comprehensive review of the reliability standard and settings every four years. Quantitative modelling of the National Electricity Market (NEM) is essential to this review. ROAM Consulting (ROAM) has been engaged by the Reliability Panel to provide modelling support for the current review. The key role of the modelling studies is to determine the reliability settings that are required for the market to continue to deliver the reliability standard. Furthermore, ROAM has investigated a range of issues relating to the effect of the reliability settings on market participants.

This report presents the findings of ROAM's modelling of the reliability settings required to deliver the reliability standard. A detailed description of the modelling methodology which is applied at all stages of this review is also provided. All financial data and forecast outcomes presented in this report are presented in real terms in July 2013 dollars unless otherwise stated.

A new approach, the "Cap Defender" analysis, has been applied in this review concurrently to the methodology used in the 2010 Review (the "Extreme Peaker" approach). Both approaches rely on a market which has a level of installed capacity that achieves Unserved Energy (USE) of 0.002% in each region. This represents a significantly lower generation reserve level compared with today's market. The two alternative approaches are summarised below:

- The **Cap Defender** Approach: Determines the Market Price Cap (MPC) required for a new entrant open cycle gas turbine (OCGT), bidding at $300/MWh, to operate profitably in a market that is expected to deliver a level of USE approaching the reliability standard. This approach is the preferred methodology for this review as it considers many factors which drive new investment in the NEM;
- The **Extreme Peaker** Approach: Assumes that a new entrant OCGT is bidding at the MPC. This approach determines a relationship between the USE observed in each iteration and the MPC required for the new entrant generator to operate profitably in a system which is expected to experience a level of USE approaching the reliability standard.

The cap defender method is the preferred approach used in this review. The cap defender approach includes commercial considerations that drive new entrant investment in the real market. Therefore, this new method is more robust and informative that the theoretical approach applied in the 2010 Review. The results of the extreme peaker method are provided in this report as a means of comparison with the 2010 Review and to provide a theoretical upper bound on the MPC required to deliver the reliability standard.

This review expands on the scope of work conducted by ROAM in the 2010 Review. We have provided additional quantitative modelling to inform the Reliability Panel on issues relating to the reliability standard, the market floor price and the potential impact of the reliability settings for market participants. This review is divided into five stages as summarised below:

- **Stage 1:** ROAM performed quantitative modelling to determine the MPC (and an associated Cumulative Price Threshold) required to allow new entrant OCGT generation to operate profitably in a market which achieves the reliability standard. This stage focused on the cap defender methodology described previously. The extreme peaker approach was also applied for comparison with the previous review;
- **Stage 2:** ROAM performed additional quantitative modelling to forecast the level of reliability in a market where the existing reliability settings are maintained. A forecast is presented for two markets over a ten year period: one with a purely market-driven development of capacity, another with no change in thermal capacity;
- **Stage 3:** ROAM also completed modelling to investigate the suitability of the current reliability standard of a maximum permissible USE of 0.002%. This modelling determines the optimum level of the reliability standard given an assumed value of customer reliability (VCR);
- **Stage 4:** The market floor price has previously been a reliability setting which has not been subject to a quantitative review. In this assessment, ROAM has performed cycling analysis based on week-ahead unit commitment (WAUC) modelling to review the suitability of the existing market floor price;
- **Stage 5:** This stage incorporates both forecast modelling and historical analysis to explore the impact that reliability settings have in the operation of the NEM. The analysis focuses on wholesale and contract markets in the NEM. We also considered how the reliability settings influence the behaviour of market participants. This stage focused on the potential impacts of a reduction in the MPC from $13,100/MWh to $9,000/MWh.

Stage 1

Figure 1 summarises the key outcomes of this stage of the study. The reliability standard in its current form states that operationally, it should be planned that the reliability standard is achieved “for each region”. We have interpreted this statement to imply that the MPC required to meet this standard is the maximum of the MPC values determined for the four mainland NEM regions. The cap defender results presented in this figure are on this basis.

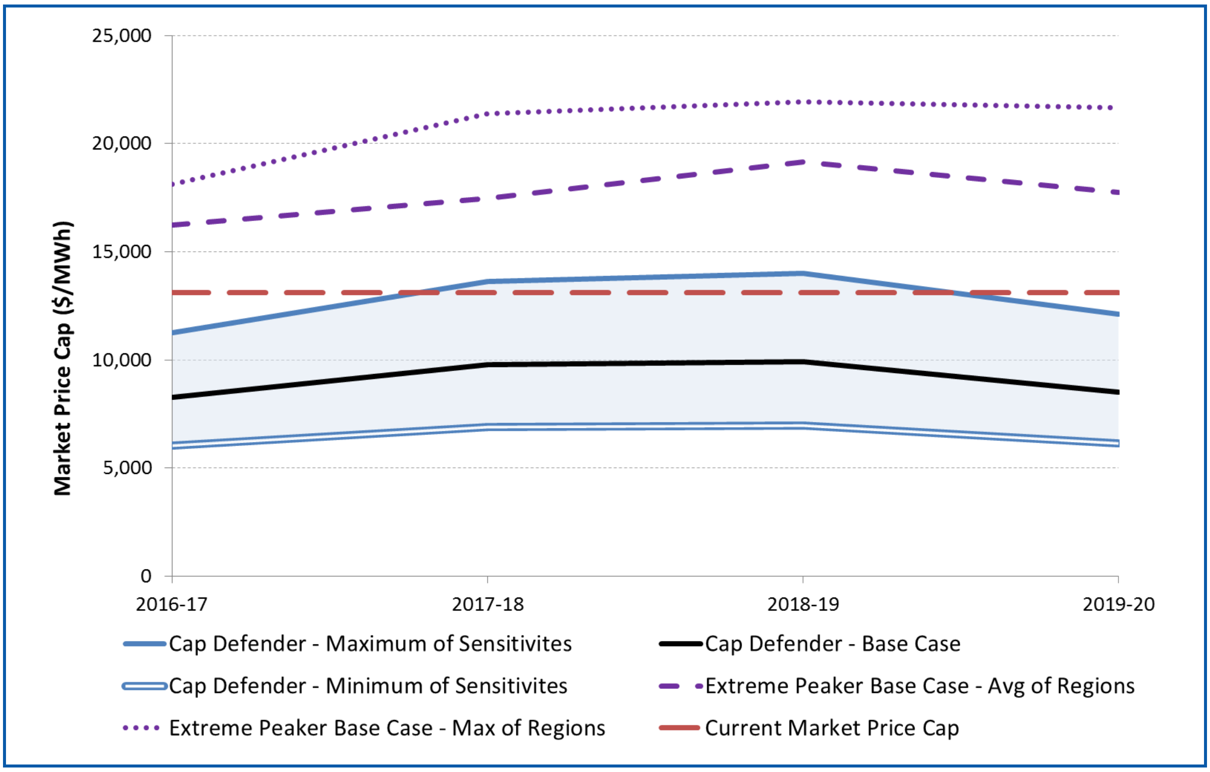

Figure 1 – Stage 1 – Market Price Cap Results

Given the significant degree of uncertainty that exists in relation to a range of input parameters, sensitivity analysis was conducted on these results. The following presents a list of input assumption sensitivities that have been analysed in this review:

- Capital cost assumptions for new entrant OCGTs;
- Alternative CPT/MPC multipliers;
- High and low demand and energy growth forecasts;
- A Reduced Large-scale Renewable Energy Target (LRET);
- A low gas price projection;
- Carbon pricing at the Treasury Core projection;
- A 50% reduction in the quantity of Demand Side Participation (DSP).

Figure 1 shows the range of MPC values calculated using the cap defender approach in the sensitivities analysed in this review. As illustrated, ROAM's quantitative modelling indicates that a reduced MPC could be sufficient to incentivise the market to deliver the reliability standard.

The results of the extreme peaker approach (in the Base Case) also appear on Figure 1 and show a significantly higher MPC requirement than the cap defender results. For comparison with the 2010 Review, the result of the extreme peaker approach as an average of each region is also provided.

The cap defender approach results in significant disparity between regions in relation to the MPC required to achieve the reliability standard. Figure 2 illustrates the disparity between the regional MPC requirements in the Base Case. The body of this report provides detailed analysis of these regional differences. The critical factors which have been found to influence these regional differences are:

- The shape of regional demand traces. In particular, the four mainland NEM regions exhibit significant differences in load factor;
- The level of energy-limited generation in each region (e.g. hydro);
- The level of interconnection between regions.

This regional disparity raises the issue of the potential application of regional MPC values. The impacts that this approach would have on the market are potentially significant and are largely unknown. The potential difficulties associated with this approach would need to be weighed against potential benefits. Such analysis is outside the scope of this study.

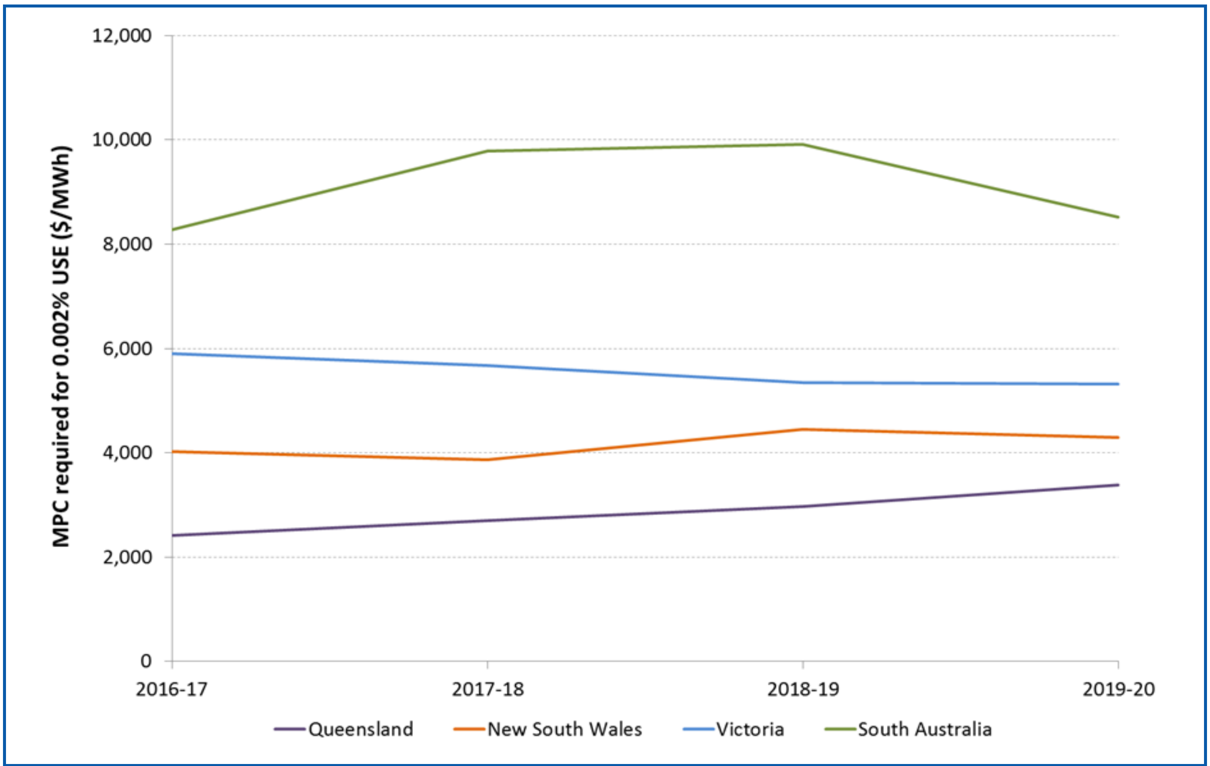

Figure 2 – Stage 1 Base Case – MPC Results

Stage 2

The results of the Stage 2 Base Case analysis are provided in Figure 3. These results are consistent with the Stage 1 results. That is, the existing reliability settings are sufficient to achieve a level of reliability in excess of the reliability standard.

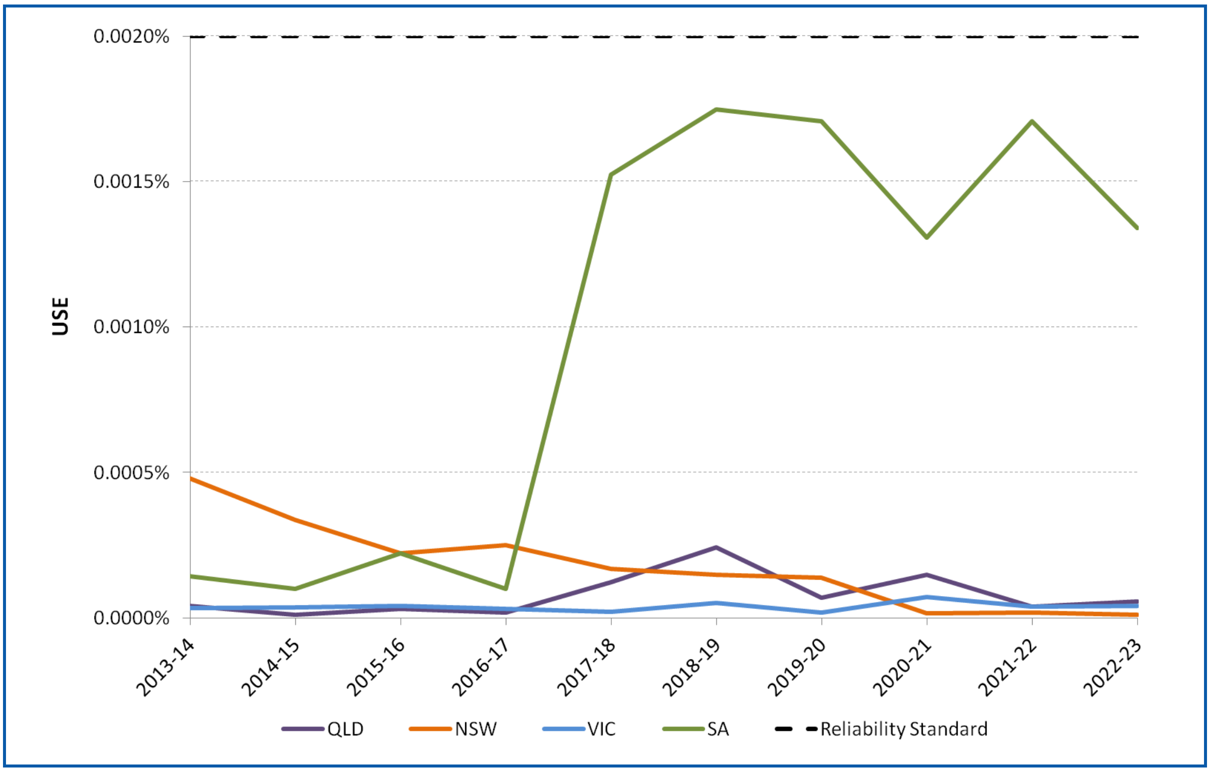

Figure 3 – Stage 2 Base Case – USE Results

Stage 3

The assessment of an economically efficient reliability standard is dependent on the value assigned to lost load. This value, the VCR, is the subject of substantial uncertainty. Therefore, we have determined a relationship between this assumed value and the level of reliability that minimises economic cost. The outcome of this study is provided in Figure 4. This figure illustrates that the existing reliability standard is optimal if the assumed VCR is approximately $30,000/MWh. The relationship between VCR and the reliability standard is observed to be relatively constant over time.

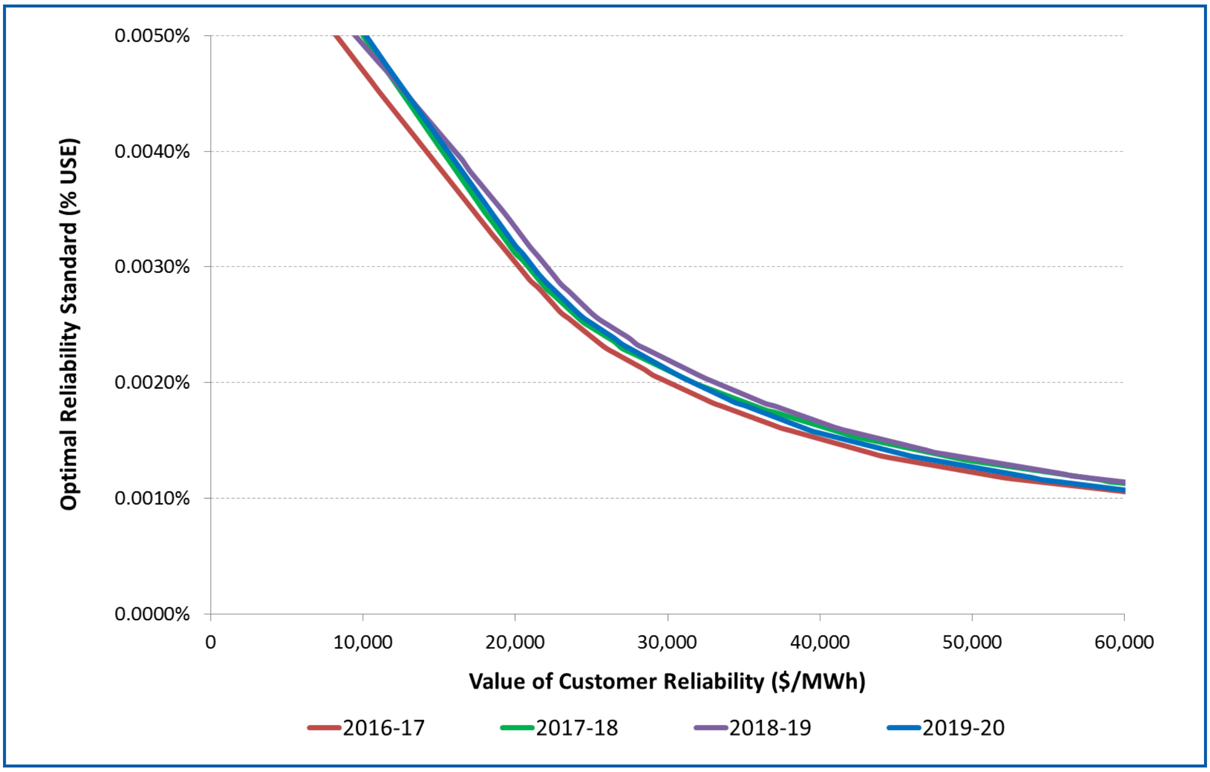

Figure 4 – Stage 3 – VCR vs Reliability Standard

Stage 4

ROAM has applied quantitative modelling to explore issues relating to the market floor price. We have applied a WAUC solver to forecast the potential unit cycling that could occur in the near future. The WAUC modelling determines the lowest cost operation of the market taking into consideration both generation and cycling costs. The results of this modelling are interrogated to determine the market floor price required to incentivise economically efficient cycling decisions.

This modelling indicates that short-term cycling of coal-fired generation units is not necessary in the near future. As a result, the modelling indicates that there is no economic imperative for a significantly negative market floor price. This analysis is based on an assumed set of cycling costs. Cycling costs are notoriously difficult to estimate given the potential impacts of cycling on unit wear and tear and outages. However, the modelling indicates that a floor price of approximately -$50/MWh is sufficient to allow an efficient operation of the market. A historical analysis of the impact of the market floor price in the NEM is also provided in this report.

Stage 5

ROAM has also completed an investigation into a broader range of issues relating to the reliability standard and settings. This includes both qualitative and quantitative analysis of historical observations and the outcomes of modelling forecasts. This assessment focused on the impact of a reduction in the MPC from $13,100/MWh to $9,000/MWh. A brief summary of the findings of this analysis is provided below:

- A reduction in MPC reduces both expected returns and the volatility of these returns for new entrant OCGT generation;
- A reduction in MPC results in a reduction in contract premiums. The impact of the MPC on contract market liquidity is less certain;
- Historical analysis of the recent past shows that trading intervals of prices at or near the MPC have been very infrequent. However dispatch interval prices have reached these levels, particularly in Queensland and South Australia. This analysis indicates that these price spikes are transient in nature and may not always provide revenue opportunities for peaking generation;
- In a market that has a level of capacity such that the expected USE is 0.002% in each region, the impact of the MPC on pool prices and therefore consumer cost is significant. In a market with a level of reserve similar to that currently being experienced, the impact of the MPC on the cost of energy is far less significant;
- A reduction in MPC does lead to a reduction in the frequency with which generation portfolios exercise transient market power. However, in a market that is oversupplied with capacity, the impact of the MPC on participant behaviour is not as significant;
- A reduction in MPC may lead to a reduction in the level of DSP. This in turn may affect the ability of the MPC to ensure that the reliability standard is met;
- Based on historical analysis, a reduction in MPC to $9,000/MWh could potentially have resulted in a reduction in negative inter-regional settlements residues of between 8% and 12% in 2011-12 and 2012-13;
- A reduction in MPC could reduce the level of basis risk for participants that engage in inter-regional contracting. However, there is limited quantitative evidence to suggest that a reduced MPC increases the ability of IRSRs to mitigate this basis risk.

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1 INTRODUCTION

1.1 BACKGROUND

ROAM has been engaged by the Australian Energy Market Commission (AEMC) to conduct quantitative modelling and to advise the Reliability Panel as part of the Reliability Standard and Settings Review. The objective of this review is to determine the reliability settings that are required to meet the reliability standard for the 2016-17 to 2019-20 period.

The current reliability standard requires the market to have sufficient capacity installed such that the level of unserved energy (USE) should not exceed 0.002% of annual energy consumption in each region. The primary objective of this review is to determine the reliability settings that will ensure that the reliability standard will be achieved. There are three reliability settings in the National Electricity Market (NEM). These are:

- The Market Price Cap (MPC), which sets the maximum wholesale market spot price which can apply in any dispatch interval;
- The Market Floor Price (MFP), which sets the minimum wholesale market spot price which can apply in any dispatch interval;
- The Cumulative Price Threshold (CPT) is a threshold which applies to the sum of the trading interval spot prices over a rolling seven day period. If this threshold is exceeded, the Administered Price Cap (APC) is applied to spot prices.

The current reliability settings for the 2013-14 financial year are as follows:

- MPC = $13,100/MWh (indexed to CPI);
- MFP = -$1,000/MWh;
- CPT = $197,100 (indexed to CPI), approximately 15 times MPC;
- APC = $300/MWh.

The MPC far exceeds the operating cost of any generator in the NEM. A high value of MPC is required as the NEM is an energy only market. Many markets, such as the South West Interconnected System (SWIS) in Western Australia, incorporate capacity payments which allow generators to recover fixed capital investments. Energy only markets do not provide capacity payments to generators. Therefore, all generators rely on pool prices exceeding operating costs in some periods of the year and/or contract revenue in order to recover their capital investment. The MPC is a setting which provides an opportunity for low utilisation plant with high operating costs to recover fixed costs in a relatively short period of operation. This report focuses on the impact of the MPC on investment in open cycle gas turbine (OCGT) generation.

ROAM has completed an extensive quantitative assessment of the reliability settings required to achieve the reliability standard. ROAM has also conducted modelling with the objective of informing the Reliability Panel on the ability of the reliability settings to achieve the reliability standard in their current form. ROAM's modelling incorporates a range of supply- and demand-side assumptions. The outcomes of sensitivities on these assumptions are intended to be indicative of a range of possible future outcomes in the NEM.

Although the primary purpose of this analysis is to examine the relationship between the reliability of the market and the reliability settings, ROAM's modelling and analysis also extends into areas which are not purely related to reliability. A quantitative assessment of the MFP has been performed which determines the range for this setting which maximises productive efficiency while ensuring that no market participant is exposed to excessive market risk. ROAM has also investigated several non-reliability implications of the reliability settings. In particular, ROAM has focused on determining the potential financial impact that a change in these settings will have on a range of market participants.

1.2 PURPOSE OF THIS REPORT

The purpose of this report is to present the findings of ROAM's modelling assessing the reliability settings required to achieve the reliability standard. It also presents an assessment of the likelihood of a breach in the standard within the next decade and an evaluation of the appropriateness of the standard from an economic perspective. Finally, some non-reliability-related impacts of a change in the reliability settings are outlined.

The report is structured as follows:

- Section 2 briefly outlines the scope for this assessment;
- Section 3 outlines the modelling approach used by ROAM in each stage of the modelling;
- Section 4 summarises the key modelling assumptions used in this assessment. Further information on the scenarios investigated by ROAM to determine the sensitivity of outcomes to these assumptions is also provided;
- Section 5 provides the outcomes of ROAM's modelling assessing the reliability settings required to achieve the reliability standard (Stage 1). A detailed analysis of these results is also included;
- Section 6 is an assessment of expected USE under a purely market-driven development of generation, as well as a future with no retirements or entry of thermal generators (Stage 2);
- Section 7 provides an economic assessment of the appropriateness of the current reliability standard (Stage 3);

- Section 8 outlines the outcomes of quantitative modelling of cost-based generator cycling and the implications for the MFP (Stage 4);
- Section 9 discusses some potential non-reliability-related impacts of changing the reliability settings on market participants (Stage 5);
- Section 10 summarises the outcomes of this assessment;
- A detailed description of the input assumptions and models used in the modelling is provided in the appendices. Appendix A provides a summary of the outcomes of the benchmark of the current methodology against the outcomes of the 2010 Reliability Standard and Settings Review[1].

2 SCOPE

The AEMC has requested that ROAM perform detailed time-sequential modelling to investigate a range of issues relating to the reliability standard and the reliability settings. The modelling that ROAM has conducted for the Reliability Panel can be broadly summarised into five stages of modelling. The five stages are designed to test each aspect of the reliability standard and settings and their potential impact on the operation of the market.

Stage 1: Conceptual Assessment of the Reliability Settings
The outcomes of Stage 1 of the assessment are of the most importance to the Panel in developing a recommendation for the appropriate reliability settings, in particular the MPC and CPT, which are required to achieve the reliability standard. The modelling in Stage 1 determines the reliability settings which will incentivise the market to meet the reliability standard between 2016-17 and 2019-20 in each region for a range of possible scenarios. Furthermore, the modelling in Stage 1 illustrates the relationship between MPC and the level of reliability in each region.

Stage 2: Assessment of the Current Market Conditions
The objective of the modelling in Stage 2 was to determine the level of reliability achieved with the current reliability settings. ROAM's modelling informs the Reliability Panel on the ability of the market to achieve the reliability standard between 2013-14 and 2022-23.

Stage 3: Assessment of the Reliability Standard
As part of this review, ROAM has also explored the appropriateness of the current reliability standard from an economic perspective.

Stage 4: Market Floor Price Assessment
The previous reviews of the reliability settings have not included a quantitative assessment of the MFP. For this review, ROAM has conducted week-ahead unit

[1] The outcomes of the 2010 Review and ROAM's accompanying report can be found here: http://www.aemc.gov.au/market-reviews/completed/review-of-the-reliability-standard-and-settings.html. Accessed 10 December 2013.

commitment (WAUC) modelling to investigate the role of the MFP in the current market. The WAUC model optimises the cycling decisions of all generators in the NEM subject to an objective of minimising avoidable costs such as fuel, VOM and startup costs.

Stage 5: Market Impacts Analysis
ROAM has completed an analysis of the potential non-reliability-related implications of a change in the reliability settings for market participants. In particular, the potential impacts of the reliability settings on the behaviour and financial risks for market participants were investigated.

All cost and forecast dollar values provided in this report are real, June 2013 Australian dollars.

3 MODELLING APPROACH

3.1 INTRODUCTION

This section outlines the methodology applied by ROAM in producing outcomes for each stage of this review. Although a unique methodology is applied in each stage of the modelling, all generation outcomes are produced using ROAM's 2-4-C software which replicates NEM dispatch.

ROAM does not determine the required reliability settings in Tasmania since reliability in Tasmania is more significantly impacted by hydrology, rather than investment signals for peaking generation. Furthermore, Tasmania has a significant capacity reserve margin over the forecast peak demand and therefore is unlikely to experience capacity reliability issues within the review period. The impact of Tasmania on the mainland NEM regions is modelled through the operation of the Hydro Tasmania generation fleet and the Basslink interconnector. Hydro Tasmania generation is assumed to operate at long term annual average production levels (approximately 8,700 GWh/annum) for the duration of the study.

3.2 STAGE 1 METHODOLOGY

Stage 1 is the most critical phase in ROAM's modelling of the reliability settings. There are a number of significant differences between the approach used in the 2010 Reliability Standard and Settings Review and in this review. In the 2010 Review, modelling conducted by ROAM applied the concept of an 'extreme peaking' generator. The extreme peaking generator was assumed to only operate in the few periods in which USE occurs (or would occur if the extreme peaking generator was not present). In submissions to the 2010 Review consultation, some market participants suggested that this was not consistent with the operation of recently commissioned OCGTs in the NEM.

Therefore, for this assessment, ROAM considered the profitability of a new entrant 'cap defender'. The cap defender is a notional, physically modelled 1 MW OCGT representing the marginal MW of a real unit.[2] It bids its entire capacity at $300/MWh. In contrast to the extreme peaker, the cap defender approach captures the ability of a new entrant generator to profitably operate at prices below the MPC. These periods may be driven by a number of factors such as high demand, generator and transmission outages, transmission constraints and the exercise of transient market power by portfolios. Given that the exercise of transient market power can impact the operation of the cap defender, it was imperative for ROAM to apply a portfolio based dynamic bidding approach in modelling generator behaviour. ROAM has applied a dynamic bidding approach in Stages 1, 2 and 5 of the modelling. See Appendix G for a description of this modelling feature.

Although the operation of the modelled new entrant peaking generator has changed significantly since the 2010 Review, the concept of this approach has not been materially altered. The principle goal of the Stage 1 approach is to determine the MPC required to allow a new entrant generator to profitably operate in market delivering the reliability standard. To conduct this assessment, ROAM retired generation such that the average USE across all iterations was 0.002% in each region simultaneously. The minimum MPC was then determined which allows the cap defender to achieve its required rate of return.

A number of market participants in the past have contested this approach. These participants have proposed that it is not appropriate to retire generation to force the market to deliver USE at the reliability standard and that the assessment of a new entrant is inappropriate in a market that has sufficient capacity installed to just meet the reliability standard. ROAM proposes that it is not the intention of these reviews that the MPC (and potentially the CPT) fluctuate wildly based on the surplus or shortage of supply at the time of each review. Furthermore, the surplus of supply at the time of the review is not certain to continue for the duration of the modelling period. There are a number of factors other than the reliability settings which may lead to capacity withdrawals or retirement, such as the need for major overhauls or fuel supply issues.

It is the intention of the reliability settings to provide an investment signal such that if the market is expected to breach the reliability standard, that a new entrant OCGT could enter the market and operate profitably. Similarly, the reliability settings should ensure that OCGT generation should not be incentivised to enter the market to profit from price volatility at the MPC if the market has more than sufficient capacity to achieve the reliability standard. This is not to exclude the possibility that new entrant OCGTs may be incentivised to enter the market for reasons other than to profit from periods where the pool price reaches the MPC.

[2] By modelling a notional 1 MW generator the potential for the generator to significantly impact on the market price outcome or to be marginal and therefore partially dispatched is removed. ROAM applies a 1 MW capacity to the new entrant to represent the *marginal* MW of investment in capacity.

In Stage 1, pool price outcomes were post-processed to apply a different MPC and CPT to all regions simultaneously. This meant that inputs such as portfolio contracting levels were not changed as the MPC was adjusted.

3.2.1 Cap Defender Approach

In the cap defender approach, a notional 1 MW OCGT bids its entire capacity at $300/MWh. This is built around the concept of a new entrant OCGT defending a $300 cap contract. This section presents the methodology used to determine the MPC required for a cap defender to operate profitably in a market which just achieves the reliability standard.

Cap Defender Revenue

The net revenue for the cap defender for a given MPC is:

$$\text{Net revenue} = \begin{matrix}\text{Pool revenue}\\ \text{net of SRMC}^3\end{matrix} + \begin{matrix}\text{Cap contract}\\ \text{value}\end{matrix} - \begin{matrix}\text{Contract}\\ \text{settlement}\end{matrix} - \begin{matrix}\text{Fixed}\\ \text{costs}\end{matrix}$$

Although the cap defender approach is conceptually built upon the idea of a new entrant OCGT selling a cap contract, the actual contracting position of the generator is not critical in this analysis. Given that this approach considers the average revenue obtained by the new entrant in all iterations, a cap contract sold at fair value is expected to have an average net payoff of $0 (i.e. the contract value is expected to equal the average contract settlement). ROAM did not evaluate the impact of cap contracts being sold at a premium to their fair value. Although historically cap contracts have sold at a premium to fair value, there is no imperative for this to continue. A qualitative discussion of the impact of contracting on MPC outcomes is included in Section 9.1.3.

Given that cap contracts were assumed to be sold at their fair value, profitability at a given MPC was independent of the level of contracting when considering the *average* of all iterations; only average results were considered in determining the MPC in Stage 1 of this review.

In contrast to the average results, in a single iteration, the profitability of the cap defender is impacted by the level of contracting. Since cap contracts were assumed to be sold at the fair value when considering all iterations, iterations that exhibited a significantly higher than average level of volatility had contract settlements that exceeded the value obtained from selling that contract. The possible impacts of MPC on revenue volatility and contracting risk are examined in detail in Stage 5 (Sections 9.1.1 and 9.1.2).

[3] SRMC refers to the Short Run Marginal Cost of a generator. The SRMC includes fuel cost, carbon cost and variable operating and maintenance costs.

Another outcome of the equality of the average contract revenue and contract settlement is that the calculation of MPC required to operate a cap defender profitably does not depend on the contract strike price.

Method for Calculating Regional MPC

The approach used by ROAM in determining the MPC required in each region is detailed below:

1. The current market was used as a starting point. The development of renewable technology was fixed to achieve the Large-scale Renewable Energy Target (LRET) specified in each scenario[4];
2. Market simulations were performed for five reference years[5] and for the 10% and 50% POE[6] peak demand forecasts. 25 Monte Carlo iterations of generator and transmission outages were conducted for each POE/reference year combination to give a total of 250 iterations for each financial year of the study. Sufficient capacity was withdrawn such that the USE in each region was approximately equal to the reliability standard when averaged across all iterations. Thermal capacity was withdrawn from each region such that the distribution of generation from the perspective of ownership, technology and cost was conserved as well as possible;
3. ROAM then performed a complete dynamic bidding simulation of this market;
4. The results of these simulations were then processed in each region to determine the MPC required (for an assumed CPT/MPC multiplier) for the cap defender to achieve its required rate of return;
5. Further sensitivities were performed to determine the MPC required for a higher and lower level of reliability;
6. A relationship was then determined between the level of reliability and the MPC requirement as illustrated in Figure 3.1. Using this approach allowed the central simulation to not exactly achieve the reliability standard. Instead, the results from the three alternative levels of reliability allowed a relationship to be determined such that the MPC corresponding to a USE of exactly 0.002% in each region could be calculated.

[4] Pool prices are sufficient to profitably operate new entrant renewable generation with LGC prices below the LRET shortfall charge.

[5] A reference year refers to a historical financial year. Observations of demand and wind and solar generation are used to forecast future financial years used in ROAM's modelling. See Appendix B for more detail.

[6] POE refers to the probability of exceedance for peak demand.

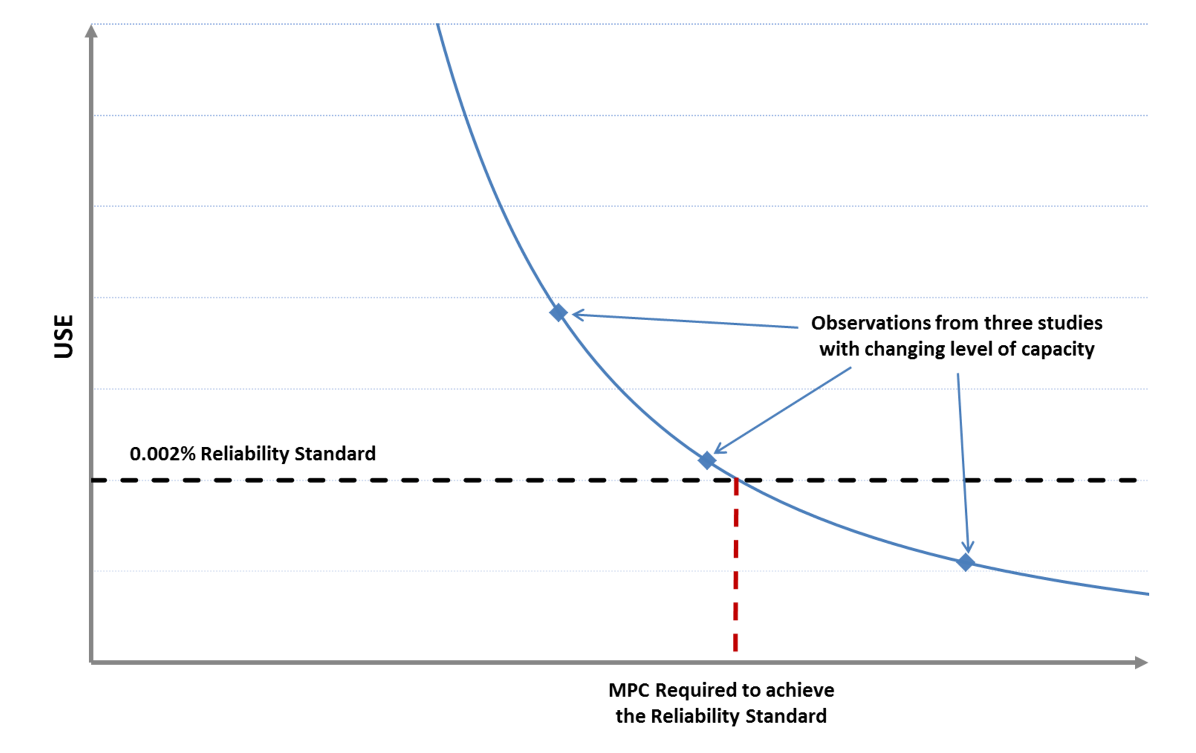

Figure 3.1 – Relationship between USE and MPC for the Cap Defender

ROAM conducted this assessment over a range of scenarios. Further sensitivities were also investigated in relation to the assumed capital cost of the new entrant OCGT and the CPT/MPC multiplier.

3.2.2 Extreme Peaker Approach

The extreme peaker is a notional 1 MW OCGT that offers all its capacity at the MPC. The net revenue of the extreme peaker used to determine the MPC at which the peaker achieves exactly its required rate of return is:

$$\text{Net revenue} = \begin{matrix}\text{Pool revenue} \\ \text{net of SRMC}\end{matrix} - \begin{matrix}\text{Fixed} \\ \text{costs}\end{matrix}$$

ROAM has maintained the extreme peaker methodology used in the 2010 Reliability Standard and Settings Review. This approach involves determining a relationship between the MPC required and the USE observed in each iteration as illustrated conceptually in Figure 3.2.

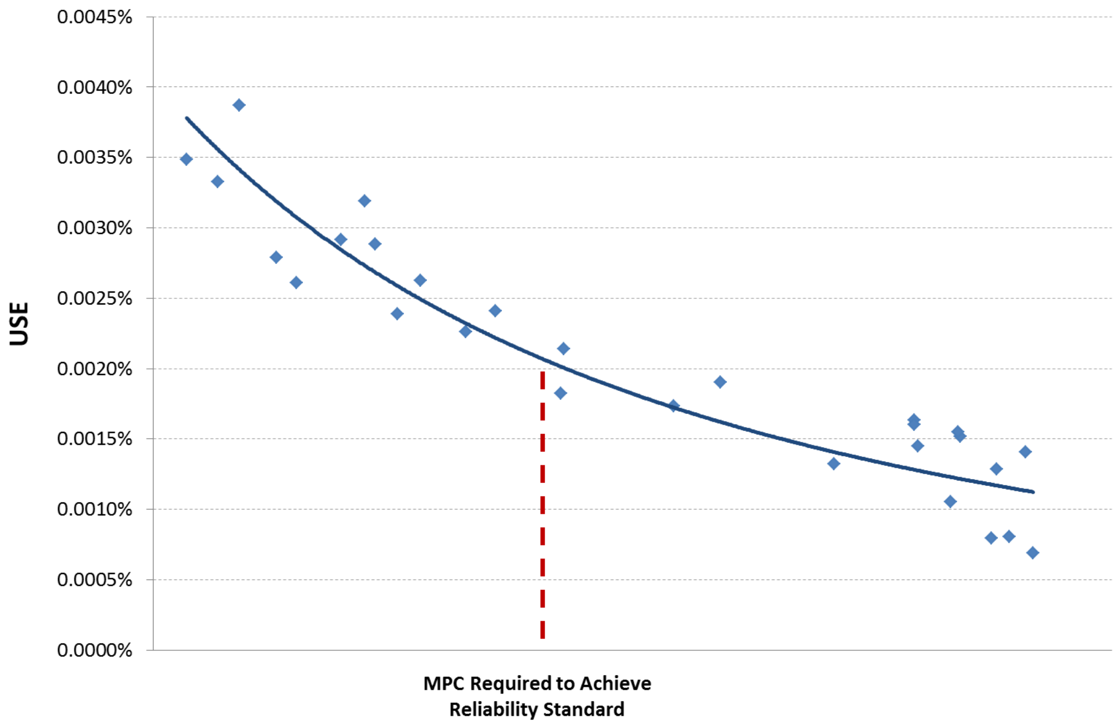

Figure 3.2 – Conceptual Illustration of the Extreme Peaker Approach

There are a number of differences between the extreme peaker approach and the cap defender approach, which is the focus of this 2014 review. The primary differences are:

1. The extreme peaker only operates in periods where USE occurs (or would occur if the extreme peaker was not present). In contrast, the cap defender operates in any period when price exceeds $300/MWh and the generator is not on a forced outage. Both the cap defender and the extreme peaker analysis are performed on the basis of the marginal MW of capacity investment;
2. The extreme peaker analysis considers the USE and revenue outcomes of each iteration individually whereas the cap defender uses the average USE and revenue of all iterations;
3. The extreme peaker analysis does not apply a CPT whereas the cap defender approach does. The CPT is not applied in the extreme peaker approach because this approach is intended to be “pure” in that it does not consider market-pricing outcomes. Market price outcomes are fundamental to the application of the CPT. With the application of CPT, administered price periods can occur during weeks of price volatility which would feature periods at MPC (and extreme peaker generation) if the APC was not applied. Since the occurrence of breaches of the CPT depends on market outcomes in the preceding week, the operation of the extreme peaker would also depend on market outcomes. This effect is therefore not considered.

3.3 Stage 2 Methodology

The objective of Stage 2 was to forecast the reliability of the NEM between 2013-14 and 2022-23 with the assumption that the current reliability settings are maintained. As with the Stage 1 modelling, the Stage 2 modelling used five reference years and both 10% and 50% POE demand forecasts; 25 iterations of each combination were simulated.

Two methods have been applied in this stage of the assessment:

- A market development plan for the Base Case;
- A projection of reliability outcomes with the existing fleet of thermal capacity in the following scenarios:
    - The Base Case;
    - The High and Low Demand sensitivities;
    - The Reduced LRET sensitivity; and
    - The Low Demand Side Participation (DSP) sensitivity.

3.3.1 Market Development

For the Base Case, ROAM performed a market driven projection of the development and retirement of thermal generation in the NEM. ROAM assumed that the development of renewable generation was fixed since development of renewable generation is unlikely to be sensitive to the level of the reliability settings and is more reflective of other policy measures. ROAM then applied an objective assessment of the retirement and entry of thermal generation. This assessment used the following assumptions:

- No hydro or wind generation was retired in the modelling;
- The capital cost of all existing generation was assumed to be a sunk cost. Therefore, only avoidable costs were considered for incumbent generators. These costs include fuel costs, carbon costs and both fixed and variable operating and maintenance expenditure;
- No portfolio positions were considered in the retirement of generation. That is, the impact that the retirement of a generator on the profitability of other assets of the same owner was not considered;
- Any plant that was not recovering fixed and variable costs in a year was assumed to retire or be mothballed. If the plant was able to operate profitably in a future year then it was allowed to return to the market. Generators were retired in descending order of loss per MW of installed capacity until all remaining generation was profitable. Partial retirements of existing units were not permitted;

- The role and ownership of a generator was not considered in the retirement of thermal plant. For example, the role of a generator in providing a physical hedge for a retailer was not considered;
- New entrant generation was only installed when it could profitably recover variable costs, fixed costs and the annualised capital cost of the investment. If any existing generator that had previously been retired or mothballed could profitably re-enter the market, it was given precedence over new entrants.

This iterative approach yielded a development plan for thermal capacity for the NEM. The modelling of Stage 2 did not directly consider whether the market was achieving the reliability standard in determining this plan. However, the level of reliability is a driver of investment, particularly for new entrant and incumbent peaking generation. The outcome of interest from Stage 2 modelling is the average volume of USE achieved in each region and in each financial year over a large number of iterations.

3.3.2 Fixed Planting

ROAM has performed a reliability assessment for both the Base Case and a range of supply and demand sensitivities[7]. The objective of this assessment was to determine the timing of new entrant generation required in each region to achieve the reliability standard. For this assessment, renewable generation was developed to meet the LRET assumption in each scenario. The thermal generation was fixed at its current level, with the exception of Mackay GT which was assumed to retire in 2017.

3.4 STAGE 3 METHODOLOGY

The objective of Stage 3 was to inform the Reliability Panel on the appropriateness of the present reliability standard. ROAM conducted modelling exploring the relationship between the installation of new capacity and reliability in the NEM. This analysis considered the combined costs of new capacity and the cost of USE.

ROAM considered a number of alternative levels of reliability in the NEM, ranging from below to above the reliability standard. ROAM then assessed the total cost of generation, including the annualised capital costs of new entrant generation, in each of the simulations. The cost of USE was valued at an assumed Value of Customer Reliability (VCR). The total cost of the market was then calculated as the sum of the cost of generation and reliability and analysed as a function of the level of USE in the market. The market is optimised from a theoretical perspective when the reliability standard corresponds to the minimum of cost. A conceptual representation of this relationship is provided in Figure 3.3.

[7] The cost sensitivities (gas price, carbon price and capital cost) have different pricing outcomes but not USE outcomes to the Base Case and so are not evaluated separately.

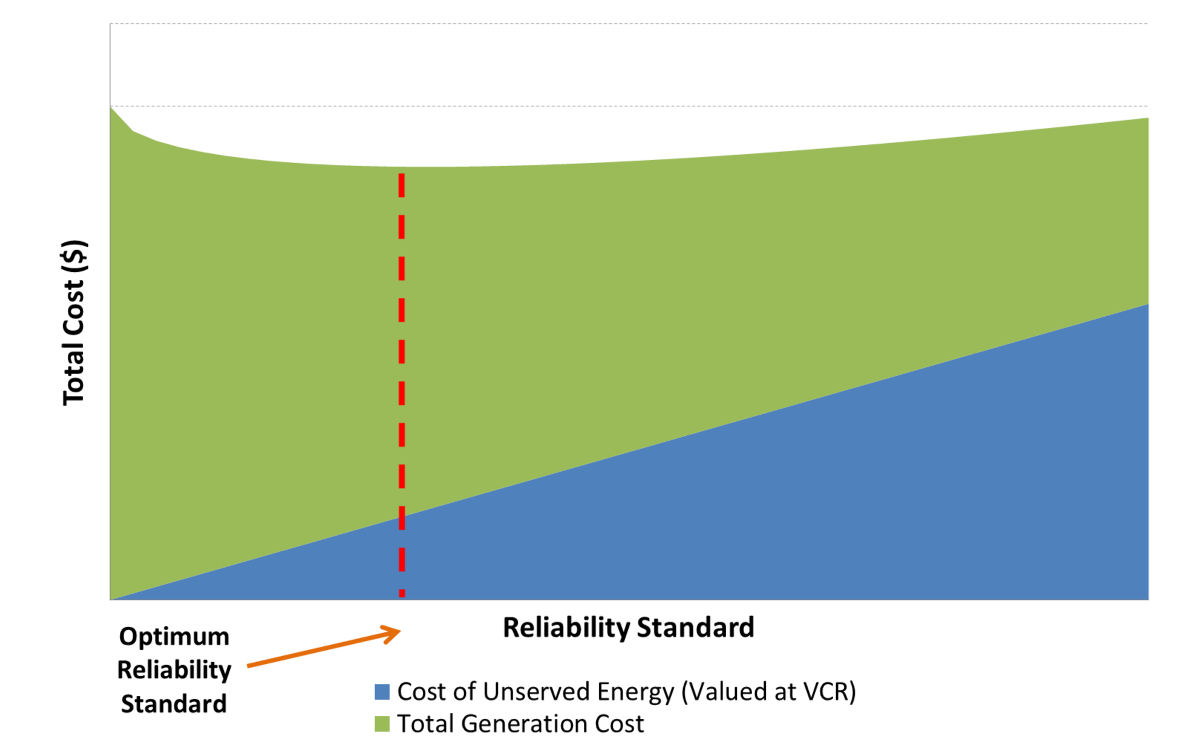

Figure 3.3 – Assessment of the Reliability Standard

There is significant uncertainty relating to the appropriate value of VCR. ROAM has therefore determined a relationship between the assumed VCR and the optimal reliability standard in the NEM.

3.5 STAGE 4 METHODOLOGY

3.5.1 Market Floor Price Considerations

ROAM proposes that there are two significant considerations for the level of the market floor price (MFP). The first of these is efficiency. If the MFP is not set at a sufficiently low value, dispatch may produce a result which is not efficient. For example, if demand was sufficiently low that all units could not operate at minimum load, an MFP of $0/MWh would provide no incentive for units with minimum loads to cycle off. The decision as to which generator should cycle would therefore become an arbitrary choice and therefore produces a potential for inefficient outcomes. The generator that cycles off may have been prepared to pay a significant price (through generating at negative prices) to continue operation due to having a high cycling cost. The efficient operation of the market allows generators with the highest cycling costs to continue to operate during periods of low demand. In Stage 4, ROAM used an assessment based on economic efficiency to determine the maximum MFP (smallest negative value) required for optimising market efficiency.

The minimum value of the MFP should take into consideration the risks to market participants. An MFP which is excessively low creates a high risk for generators and potentially, contracted retailers. The MFP can result from transient market issues which have no relation to generator cycling (see Section 0). Consequently, an MFP which is too low increases risks for market participants while having no value from an efficiency perspective.

There is significant uncertainty relating to the actual cost of cycling. There is no public source of information relating to the cost of cycling in the NEM. Furthermore, cycling costs are notoriously difficult to estimate. ROAM has used publically available estimates of cycling costs for different technologies (see Section 4.7) and consulted with stakeholders to ensure these values are broadly appropriate for plant in the NEM. However, inferences drawn from the outcomes of this modelling should still take the large uncertainty in cycling costs into account.

3.5.2 Dispatch Modelling for Market Floor Price Assessment

ROAM's assessment of the MFP is based on a WAUC feature in 2-4-C, which is capable of assessing the relationship between the MFP and decision making by generators as to whether to cycle generation. The WAUC model optimises the cycling decisions of all generators in the NEM subject to an objective of minimising cost over the coming week. Cost in this instance refers to the avoidable costs (fuel and VOM) and startup costs provided to the model. A week-ahead commitment model was appropriate since the MFP should be less than or equal to the highest cost (most negative value) for units that cycle. Longer-term cycling would have a lower cost per MWh and therefore will not set the MFP.

ROAM has run the WAUC model applying the cycling cost assumptions provided in Section 4.7. The outcomes of this modelling are intended to inform an investigation of the suitability of the current MFP.

The market simulated for this assessment included the following generators:

- all existing generators remain operational except for Mackay GT, which retires in 2017. All Tarong units are returned to service;
- sufficient renewable capacity is installed to meet the LRET;
- a new 120 MW CCGT is installed in Queensland in 2018.

This market was chosen to give the maximum foreseeable supply in order to maximise the need for cycling and therefore compute the lower bound of the MFP.

ROAM has applied both warm and hot start cycling cost assumptions in the WAUC modelling. Warm starts capture the incentive for units to turn off for relatively long periods of time (over 12 hours) in response to low demand conditions. Hot starts allow generation to cycle off for relatively short periods and are more closely linked with the relationship between demand and the quantity of must-run generation operating at any point in time.

3.5.3 Economic Analysis

ROAM's assessment of the maximum MFP required for market efficiency is based on an analysis of the cycling decisions resulting from the WAUC modelling. ROAM determined the set of units which were cycled off in the modelling. For each of these generators, the maximum MFP was then calculated using the following formula:

$$\text{MFP} < \text{SRMC} - \frac{\text{Total Cycling Cost (\$)}}{\text{Min Load} \times \text{Hours off-line}} \qquad (1)$$

As long as the MFP is below this value, a generator only chooses to cycle if it is financially beneficial to do so. ROAM determined the minimum of the MFPs required for all generators that cycled. This value is the maximum MFP required to achieve economically efficient cycling.

3.6 STAGE 5 METHODOLOGY

We analysed the potential impact of changing the MPC based on historical market data as well as two different modelled markets for the period 2016-17 to 2019-20. The two modelled markets were:

- A market with expected USE of 0.002% (Stage 1, Base Case). This market incorporates significant retirements of existing capacity. The market provides an upper bound on the level of volatility that could occur in a market that is achieving the reliability standard;
- A market with surplus capacity which represents a more realistic possible future for the NEM. In this market, renewables are installed to meet the LRET, half of Hazelwood (800 MW, 4 units) and all of Wallerawang (1,000 MW, 2 units) are retired before 2016-17, Mackay GT retires in March 2017 and a 250 MW CCGT is installed in South West Queensland in 2019-20. The choice to retire Hazelwood and Wallerawang was not based on particular consideration of the operation of these units.

The second market is intended as a more realistic possible future state of the NEM than the first since the current supply-demand balance is such that expected USE in the study timeframe is well below 0.002% in all regions except Queensland. In contrast to the other regions, Queensland is likely to experience generation shortfalls within the next seven years (in the absence of new generation development) as a result of increased energy demand relating to LNG gas developments.

In the dispatch modelling, the effects of the current MPC of $13,100/MWh were compared to an alternative MPC of $9,000/MWh. The value of the alternative MPC was chosen in consultation with the Reliability Panel based on the outcomes in Stage 1 but does not form a recommendation.

Our analysis has focused on the possible impacts of the MPC on a range of market participants. The issues covered in the Stage 5 analysis include:

- The potential impact of MPC on the volatility of returns for new entrant generation;
- The relationship between volatility and the level of contracting. Further discussion is provided on the relationship between the MPC and contract markets;
- A historical analysis of price volatility in the recent past. This analysis focuses on the effect of the MPC in a market which is oversupplied with capacity;
- The possible impact of the MPC on consumers;
- The influence of the MPC on the behaviour of generation portfolios in the NEM;
- The relationship between the level of DSP and the MPC;
- A historical assessment of the effect of a lower MPC on negative settlements residues.

4 KEY MODELLING ASSUMPTIONS AND SCENARIOS

4.1 *DEMAND ASSUMPTIONS*

As a central estimate, ROAM used medium peak demand and energy forecasts published by the Australian Energy Market Operator (AEMO) in the 2013 National Electricity Forecasting Report (NEFR)[8].

Of particular importance to reliability of supply is the projection of regional peak demand growth. AEMO's projections of peak demand have declined considerably in the previous two years. The current peak demand projections for the 10% POE case for the mainland NEM regions are provided in Figure 4.1 alongside the low and high projections which are used in the demand sensitivities (see Section 4.6.1). These figures illustrate that with the exception of Queensland, peak demand does not increase dramatically by 2022-23 and is projected to reduce in South Australia. Annual energy in the medium case is illustrated in Figure 4.2 alongside the low and high projections.

[8] Australian Energy Market Operator, June 2013, *National Electricity Forecasting Report (NEFR) 2013*. Available at: http://www.aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report-2013.

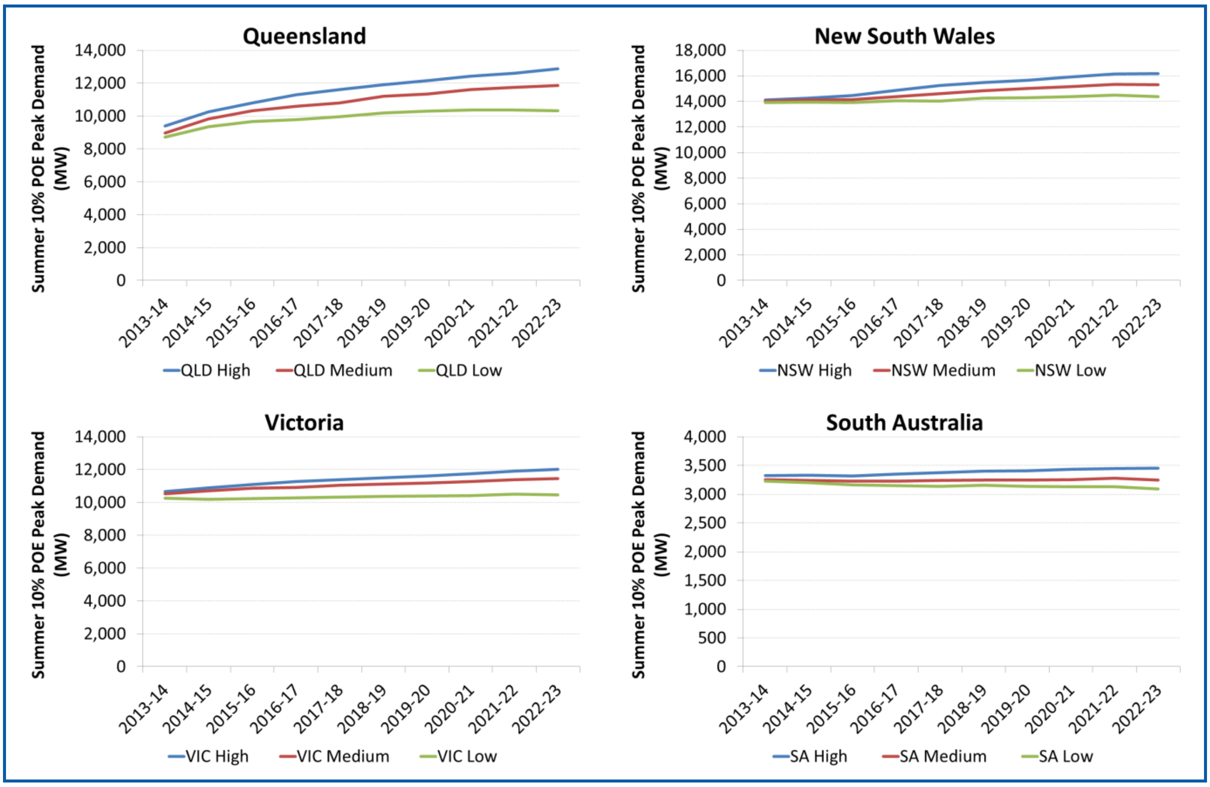

Figure 4.1 – Regional 10% POE Summer Native Peak Demand Projections

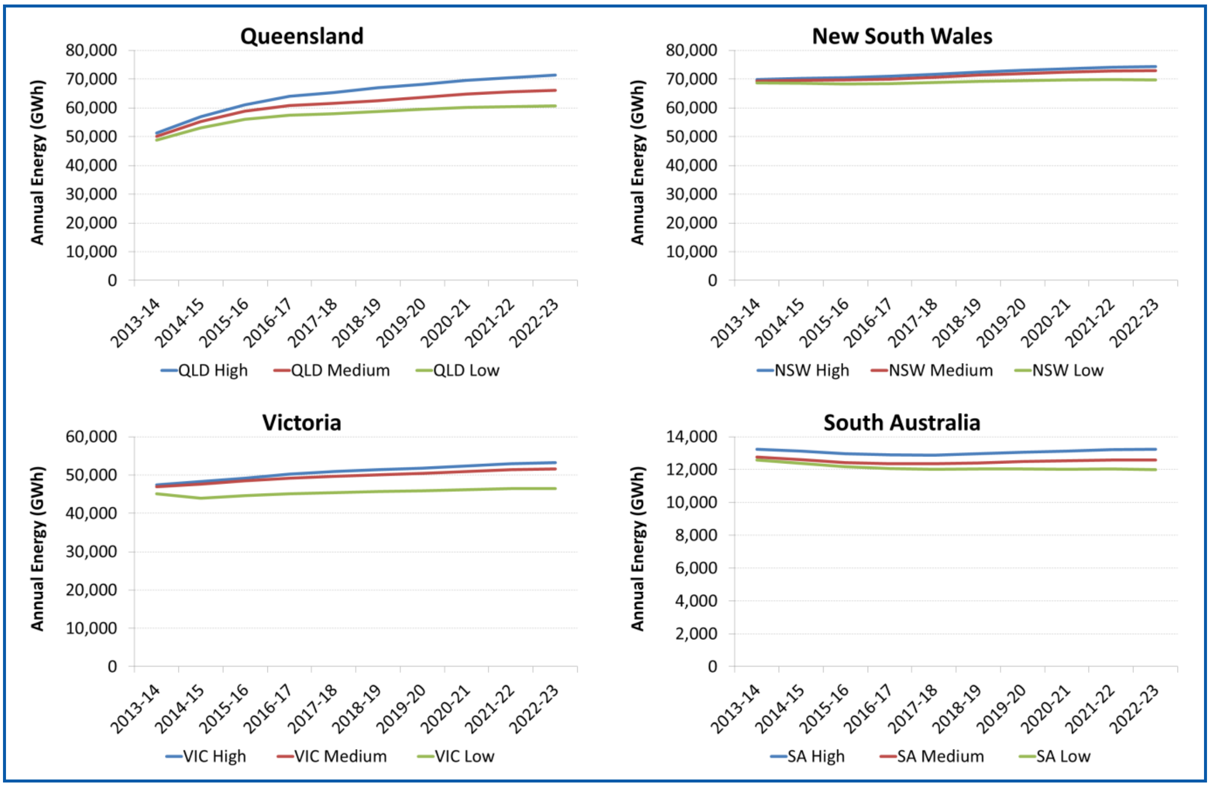

Figure 4.2 – Regional Native Energy Projections

Weather is a key driver of demand. Winter and summer peak demand forecasts coarsely capture the severity of weather events in forecast years; however, a forecast of demand for the single seasonal peak demand period does not capture aspects of the weather such as heat waves or extended cold periods. The overall shape of demand, particularly at and near to the peak demand is of critical importance to the operation of peaking generation and the volume of USE. The shape and volume of USE is of particular importance to operation of the extreme peaker. It has a more indirect impact on the operation and outcomes of the cap defender; load factor influences pricing outcomes, which in turn influences the operation of the cap defender.

In order to create a half-hourly forecast demand trace, ROAM used demand shapes from historical reference years and annual energy and peak demand targets supplied by AEMO in the NEFR. The historical trace is extrapolated to meet the forecast targets while preserving the time of summer and winter peaks in a given region, the overall shape of demand and the coincidence of inter-regional peak demands. In this review, ROAM used five reference years (2008-09 to 2012-13) to incorporate a range of possible demand distributions in the modelling. Further detail of demand shape across the five reference years can be found in Appendix A.

For each reference year, ROAM used half-hourly correlated demand and intermittent energy production, based on all present and future anticipated wind and solar projects for each year of modelling. Detail on ROAM's treatment of rooftop PV and large-scale renewables is given in Appendix C and Appendix D.2 respectively.

ROAM has modelled the 10% and 50% POE forecasts in each simulation. These 10% and 50% POE cases represent upper and lower bounds. To show the 'likely' case, ROAM calculates a 'weighted' value for all properties. This weighted value is calculated as 30% of the 10% POE value and 70% of the 50% POE value. This weighting reflects AEMO's assessment of the relative weightings that should be applied to account for the shape of peak demand distribution. All outcomes presented in this report are calculated using this weighting methodology.

4.2 TRANSMISSION CONSTRAINT EQUATIONS

ROAM has incorporated the limitations of the transmission system in all dispatch modelling by applying the set of system normal constraint equations published by AEMO as part of their Planning Studies. The complete set of system normal constraint equations captures the capability of the transmission network both within regions (intra-regional) and between regions (inter-regional). In the operation of the NEM, many intra-regional transmission network limitations are appropriately captured by including the interconnector term in the constraint equation. This effectively reflects the capability of generation and the transmission network to supply an increment of load at the respective regional reference node. The location of generation and the transmission capability affect both market price outcomes and reliability of supply outcomes.

For the purpose of assessing the operation of the peaking generator that informs the MPC analysis, the peaking generator was effectively located at the regional reference node such that it does not face congestion risk in its dispatch or associated pricing outcomes as this could heavily bias outcomes. Similarly, the new entrant OCGT is assumed to have a marginal loss factor (MLF) of 1, consistent with its hypothetical regional reference node location.[9]

ROAM has applied the committed upgrade of the Heywood interconnector in this modelling.

4.3 INTERCONNECTOR OUTAGES

Random outages have been applied to interconnectors. Both full and partial outages are applied to DC interconnectors while only partial outages are applied to AC interconnectors as these interconnectors represent a number of transmission flow paths. Transmission outage rate assumptions are sourced from the 2006 MRL recalculation which is the latest available set of data. Transmission outage data is provided in Table 4.1.

Table 4.1 – Transmission Forced Outage Assumptions

	Full Forced Outage Rate	Partial Forced Outage Rate	Partial Derating	Nominal Capacity (MW)
Terranora North	0.163%	1.150%	33.333%	234
Terranora South	0.047%	1.150%	33.333%	105
QNI North	-	0.503%	50%	1078
QNI South	-	0.503%	63.158%	486
VIC-NSW North	-	0.299%	33.333%	3200 – Lower and Upper Tumut
VIC-NSW South	-	1.338%	33.333%	1900 – Murray
Heywood West	-	3.46%	50%	460 to 30/6/2015 650 from 1/7/2016
Heywood East	-	3.46%	50%	460 to 30/6/2015 650 from 1/7/2016
Murraylink West	0.7%	1.115%	100%	220
Murraylink East	0.7%	1.115%	100%	220
Basslink North	0.188%	0.18%	26.33%	594
Basslink South	0.188%	-	-	478

[9] Both the congestion and MLF assumptions likely result in a low estimate of the MPC required given that many locations, particularly in zones where generators typically locate, are associated with MLF values of less than 1. Therefore, the consideration of both congestion and MLF would decrease the revenues earned by the new entrant OCGT and consequently increase the MPC requirement.

4.4 OCGT ASSUMPTIONS

4.4.1 Capital Costs

ROAM's central estimate of annualised capital cost for a new OCGT is \$100,000/MW/annum. This value was deemed to be an appropriate central estimate because calculations of annualised capital cost using several data sets with varying capital cost (\$/MW), connection cost and WACC result in a similar value, as detailed in Appendix E.

4.4.2 Operating and Maintenance Cost

ROAM used operating and maintenance cost estimates from the Bureau of Resources and Energy Economics (BREE) *Australian Energy Technology Assessment*.[10] The fixed operating and maintenance cost (FOM) was \$4,049/MW/annum, while the variable operating and maintenance cost (VOM) was \$10.24/MWh sent-out. No escalation in real terms of operating and maintenance cost was applied.

4.4.3 Forced Outage Rate

Generator availability is another critical input in the assessment of the profitability of new entrant OCGTs. Higher forced outage rates decrease the revenue earned by the peaking generator and create a risk for the generator assumed to be operating under a cap contract.

ROAM applied a 3% full forced outage rate for new entrant peaking generation which is consistent with the expected reliability of new entrant best practice peaking generation. This provides a potentially conservative (i.e. low) estimate of the MPC. Similarly, the 1 MW size of the modelled unit means it is unlikely to be marginally dispatched. This also contributes towards a potentially conservative estimate of MPC.

4.5 OTHER TECHNOLOGIES ASSUMPTIONS

For existing generators in the NEM, ROAM used technical and cost assumptions from the AEMO Planning Assumptions for 2013[11]. For new entrant generation, ROAM used data from BREE's *Australian Energy Technology Assessment*[12], but did not apply operating and maintenance cost escalation in real terms.

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[10] Bureau of Resources and Energy Economics, 2012, *Australian energy technology assessment*. Available at: http://www.bree.gov.au/publications/aeta.html. Accessed: 15th August 2013.

[11] Australian Energy Market Operator, June 2013, *2013 Planning Assumptions: Existing Generation Data*. Available at: http://www.aemo.com.au/Electricity/Planning/Related-Information/2013-Planning-Assumptions. Accessed 16th August 2013.

[12] Bureau of Resources and Energy Economics, 2012, *Australian energy technology assessment*. Available at: http://www.bree.gov.au/publications/aeta.html. Accessed: 15th August 2013.

The central fuel cost assumptions were sourced from the AEMO Planning Assumptions for 2013.

4.6 MODELLING SENSITIVITIES

ROAM collaborated with the AEMC and the Reliability Panel to develop a range of alternative scenarios to inform the determination of the reliability settings required to achieve the reliability standard.

The Base Case in this modelling incorporated the following assumptions:

- Medium demand and energy projections;
- The mandated LRET scheme targeting approximately 41 TWh of renewable energy generation by 2020;
- The central gas price trajectory provided in the AEMO Planning Assumptions 2013;
- A repealed carbon price;
- An annualised capital cost of $100,000/MW/annum for OCGT capacity;
- DSP quantities and price thresholds from the 2013 AEMO NEFR.

The sensitivities that have been developed for this analysis include:

- High and low capital cost assumptions for the new entrant OCGT;
- Two alternative CPT/MPC multipliers; 12 times and 18 times the MPC;
- High and low demand and energy growth forecasts;
- A Reduced LRET GWh target;
- A low gas price projection;
- Carbon pricing at the Treasury Core projection[13];
- A 50% reduction in the quantity of DSP.

4.6.1 Demand and Energy Growth Sensitivities

ROAM used peak demand and energy forecasts published by AEMO in the 2013 NEFR. The High Energy and Low Energy sensitivities use the high and low growth scenarios respectively, while all other modelling including the Base Case used the medium growth projections. Peak demand in the High and Low Energy sensitivities can be seen in

[13] Australian Government Treasury, September 2011, *Strong Growth, Low Pollution: Modelling a Carbon Price, Chart 5.1: Australian carbon price*, Available at: http://archive.treasury.gov.au/carbonpricemodelling/content/chart_table_data/chapter5.asp

Figure 4.1 for the 10% POE case, alongside the central peak demand estimate, while Figure 4.2 shows annual energy in the three projections.

4.6.2 Reduced LRET Sensitivity

The penetration of renewables is a potentially important factor in the assessment of reliability and in determining the relationship between USE and MPC. To assess the impact of renewables, ROAM considered a Reduced LRET sensitivity.

In the Base Case, ROAM modelled the current legislated LRET of approximately 41 TWh of new renewable generation by 2020 Australia-wide[14]. For the Reduced LRET sensitivity, ROAM considered an LRET trajectory that targets sourcing 20% of energy in 2020 from renewables, based on current energy forecasts. This corresponds to approximately 29 TWh of new renewable generation by 2020 across Australia (comprising 27 TWh LRET liability and 2 TWh Green Power liability). The renewables development plans used in the central LRET trajectory and Reduced LRET sensitivity are shown in Appendix D, along with details of the calculation of the Reduced LRET.

4.6.3 Gas Price Sensitivity

Potential future gas prices will be a driver for determining the type of new entrant generation in the NEM. This may be particularly relevant as the high gas costs projected over the next ten years mean that the cost of generation for Combined Cycle Gas Turbines (CCGTs) is high. ROAM has developed a low gas price trajectory with the objective of investigating the impact of the gas price on reliability of supply and the MPC. The central estimate of the gas price for a CCGT and the trajectory in the Low Gas sensitivity are shown in Figure 4.3. A 25% premium is applied to gas costs for an OCGT for all cases.

[14] This represents new renewable generation above generation from hydro pre-existing at the start of the scheme. It also assumes that the extra 850 GWh liability added to the target in December 2011 when waste coal mine gas was included in eligible generation is met by waste coal mine gas exactly.

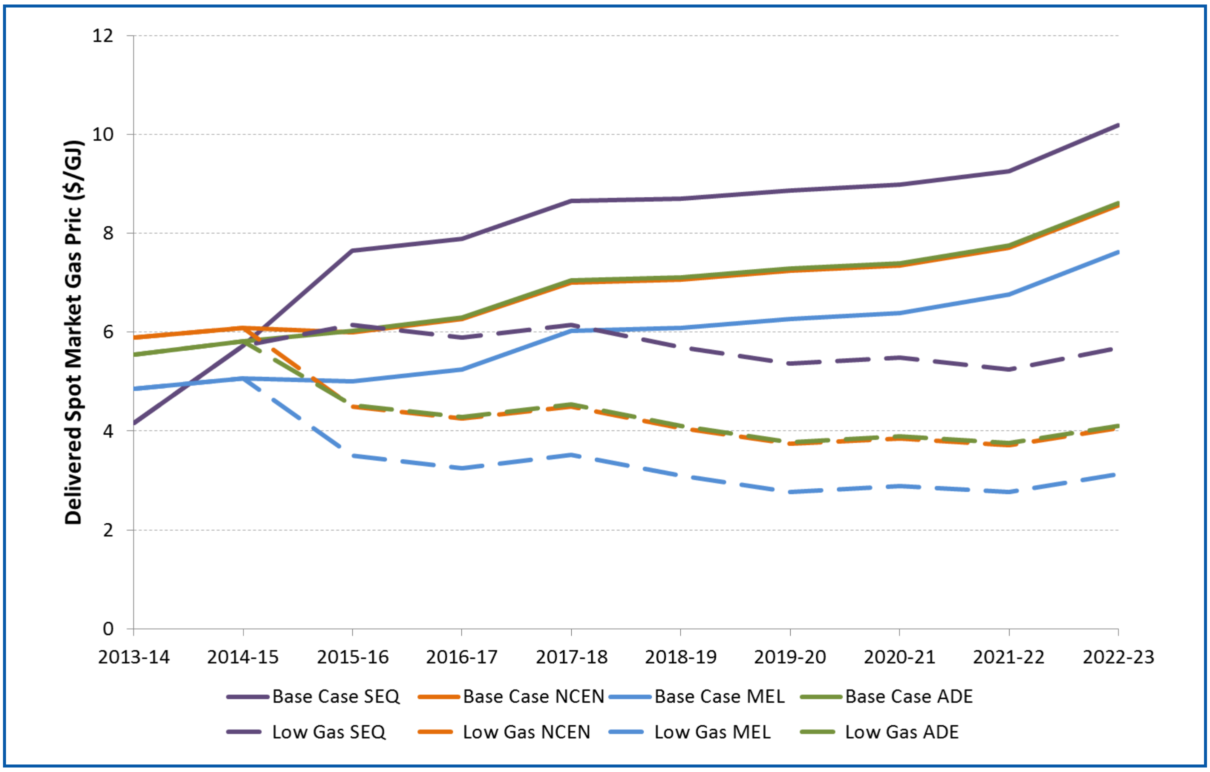

Figure 4.3 – Gas Price Trajectories for a CCGT in the Base Case and Low Gas Price Sensitivity

4.6.4 Carbon Price Sensitivity

There remains significant uncertainty surrounding carbon pricing in Australia throughout the study period. Current legislation specifies a fixed price period to 30 June 2015, followed by flexible pricing with a link to the European Union's scheme. However, the new federal government elected in September 2013 is working towards removing carbon pricing. Since the new Senate does not start until 1 July 2014, ROAM has assumed that a repeal will not be possible until 1 July 2015 (Figure 4.4, blue line). In the absence of detailed policy, "Direct Action" under the Coalition is assumed to have no impact on the stationary energy sector. ROAM has not considered a reintroduction of carbon pricing within the study period.

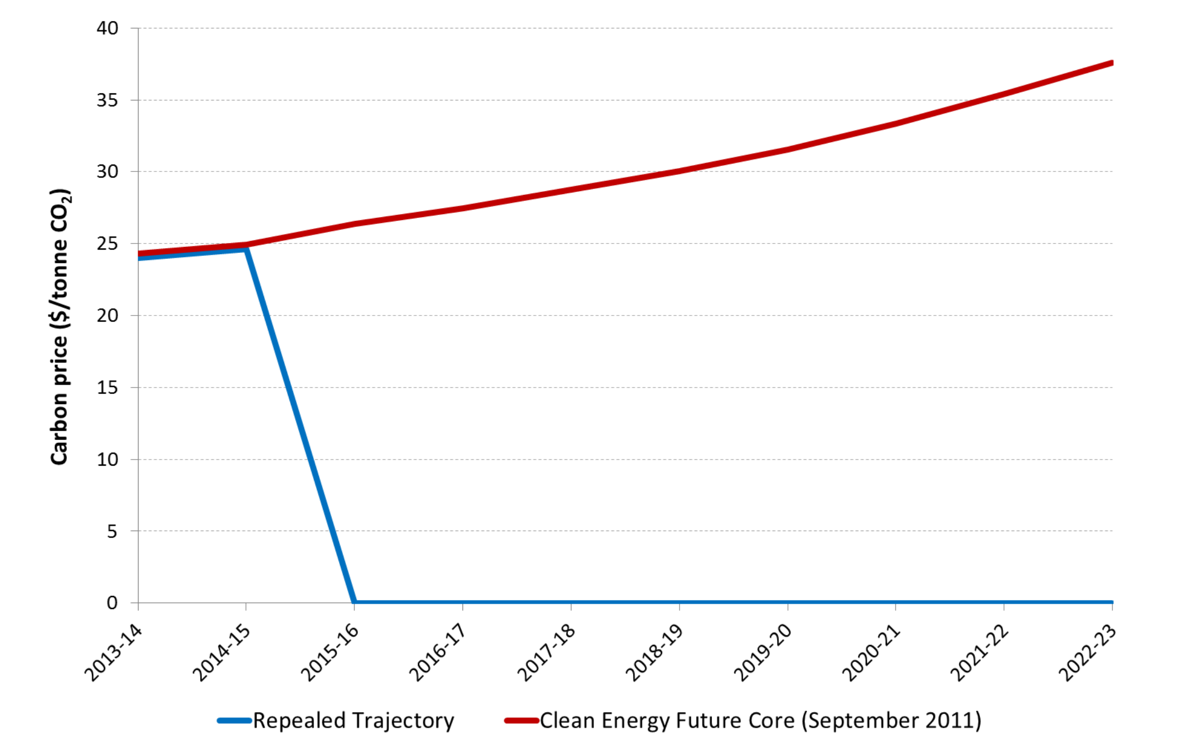

Figure 4.4 – Australian Carbon Price Trajectories

For the carbon price sensitivity, ROAM analysed outcomes under the Treasury Core trajectory (Figure 4.4, red line). Although this trajectory features short-term pricing which is unlikely to occur, the sensitivity was designed to clearly demonstrate the magnitude of the effect of the carbon price on MPC outcomes.

4.6.5 Capital Cost Sensitivity

To determine the sensitivity of MPC outcomes in Stage 1 to capital cost assumptions, ROAM examined the effect of a 20% decrease and a 20% increase in the central annualised capital cost of $100,000/MW/annum.

Since this is an annualised value, the change could result from a different WACC, financial term or underlying capital cost in $/kW as shown in Table 4.2.

Table 4.2 – Variation in WACC, Financial Term or Capital Cost

Scenario	Capex ($/kW)	WACC (real, pre-tax)	Financial Term (years)	Annualised capex ($/MW/annum)
Base Case	854	10.0%	20	100,000
High Capital Cost	854	10.0%	**13**	120,000
High Capital Cost	854	**12.8%**	20	120,000
High Capital Cost	**1022**	10.0%	20	120,000
Low Capital Cost	854	**6.9%**	20	80,000
Low Capital Cost	**681**	10.0%	20	80,000

4.6.6 DSP Sensitivity

The Standing Council on Energy and Resources (SCER) has formally requested AEMO lead the implementation of a Demand Response Mechanism[15] including:

- A new option for demand resources to participate in the NEM;
- A new category of market participant to allow the unbundling of ancillary services from the sale and supply of electricity.

A class of participant is able to offer demand curtailment at the market price in up to ten price/volume pairs as for generators. The 'dispatch' of demand curtailment based on pricing outcomes is recorded at the half-hourly level as per all other market data. The capacity availability and price offers for demand response are an important input assumption.

As a central estimate, ROAM used the level of demand response capacity published in the supplementary information to the AEMO NEFR 2013. Table 4.3 shows the cumulative DSP capacity at several price points in 2016-17, while Table F.1 in Appendix F shows how this capacity changes over time.

The level of DSP in the NEFR is determined through an historical analysis of industrial load response to pool prices. The DSP capacity estimated using this method is significantly larger than previous AEMO estimates of DSP capacity and several market participants have indicated they believe these estimates to be high. Therefore, ROAM conducted a sensitivity analysis by reducing the capacity of DSP available in each price band by 50% (Table 4.3).

[15] http://www.scer.gov.au/workstreams/energy-market-reform/demand-side-participation/wholesale-market-demand-response-mechanism-in-the-national-electricity-market/

Table 4.3 – Summer DSP Comparison – 2016-17

	2013 NEFR Forecast		Low DSP Sensitivity	
Region	**Price ($/MWh)**	**Capacity (MW)**	**Price ($/MWh)**	**Capacity (MW)**
Queensland	≥ 1,000	58	≥ 1,000	29
	≥ 7,500	70	≥ 7,500	35
	MPC	148	MPC	74
New South Wales	≥ 1,000	21	≥ 1,000	10.5
	≥ 7,500	56	≥ 7,500	28
	MPC	195	MPC	97.5
Victoria	≥ 1,000	121	≥ 1,000	60.5
	≥ 7,500	259	≥ 7,500	129.5
	MPC	453	MPC	226.5
South Australia	≥ 1,000	34	≥ 1,000	17
	≥ 7,500	41	≥ 7,500	20.5
	MPC	72	MPC	36
Tasmania	≥ 1,000	3	≥ 1,000	1.5
	≥ 7,500	37	≥ 7,500	18.5
	MPC	67	MPC	33.5

4.7 CYCLING ASSUMPTIONS

ROAM has completed an extensive literature review to determine an appropriate set of cycling cost assumptions to be applied in Stage 4. We have determined that the National Renewable Energy Laboratory[16] provides the most comprehensive assessment of the costs of cycling thermal generation. Cycling analysis was conducted using both "warm start" and "hot start" cycling assumptions. The "hot start" assumptions apply to coal generation only. These assumptions are provided in Table 4.4. Although all plant of the same type will operate with the same cycling cost on a $/MW of capacity basis, differences in minimum load assumptions, unit size and operating costs will influence cycling decisions.

[16] National Renewable Energy Laboratory, April 2012, *Power Plant Cycling Costs, Available at:* http://www.nrel.gov/docs/fy12osti/55433.pdf

Table 4.4 – Cycling Cost Assumptions

Plant Type	Warm Start Cycling Cost ($/MW nameplate)	Hot Start Cycling Cost ($/MW nameplate)	NEM Example
CCGT	102	102	Pelican Point
Supercritical coal	445	274	Kogan Creek
Large sub-critical coal	290	227	Bayswater
Small sub-critical coal	328	241	Hazelwood

4.8 OVERVIEW OF MODELLING FEATURES

ROAM's modelling is based on a number of assumptions which may provide either a conservative or optimistic estimation of the profitability of a new entrant OCGT. These are summarised below.

4.8.1 New Entrant Assumptions

Locational Assumptions

Section 4.2 indicated that the hypothetical reference node location of the OCGT may provide an optimistic estimate of profitability. That is, the MLF of 1 and the protection of the generator from curtailment are not necessarily obtainable for all new entrant generation. The location of the new entrant away from the reference node could result in an MLF of less than 1 and a portion of revenue lost due to curtailment. This would result in a higher MPC requirement.

Unit Size

ROAM has examined the assumed 1 MW size of the new entrant OCGT. Modelling has shown that this assumption, based on the concept of the "marginal" MW of investment, yields a slightly conservative estimate of the MPC. The effect of larger unit sizes (up to 200 MW) has been tested. This effect was found to be relatively immaterial. The last MW (represented by the 1 MW theoretical new entrant) is theoretically the least profitable MW of investment. By increasing the size of the unit (and withdrawing additional capacity of a similar size to achieve 0.002% USE), frequency of dispatch is increased. However periods of increased dispatch occur when the cap defender is marginal, and pool price is at $300/MWh. These periods do not contribute significantly to the repayment of capital investment and do therefore not materially change the MPC requirement.

ROAM has also found that the increase in the size of the standalone merchant OCGT can slightly dilute market concentration and result in a slight reduction in pool price volatility. This has the effect of slightly increasing the MPC requirement.

4.8.2 Trading Interval Modelling

ROAM's modelling is performed on a trading interval basis. This has mixed effects on the profitability of the new entrant OCGT. By modelling on a trading interval basis, ROAM is not capturing volatility which results from dispatch interval effects such as ramp rates and fast start inflexibility profiles. Therefore, the estimates of volatility may be conservative. However, volatility which is an outcome of dispatch interval effects is often transient and may therefore not be captured by OCGT generation. The trading interval modelling assumes that the OCGT is always able to fully capture price volatility that does occur, excluding periods where the unit is on a random or planned outage. Therefore, trading interval modelling has both optimistic and conservative elements in its effect on profitability and therefore MPC.

4.8.3 Contract Premiums

ROAM has not accounted for cap contracts trading at any premium above their fair value. The potential for contracts to trade at above their fair value is examined in Section 9.1.1.

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5 STAGE 1 RESULTS

This section presents the results of modelling conducted to determine the MPC required to achieve the reliability standard in a range of scenarios. In particular, this section provides a detailed examination of the results of the Base Case. Sensitivity results are presented to illustrate the relationships between the MPC and a range of input parameters.

5.1 STAGE 1: BASE CASE

5.1.1 Introduction

It has previously been discussed that Stage 1 requires that the market is approximately achieving the reliability standard in each region and in each year of the study. Given the recent decline in forecast demand growth, the increased penetration of wind generation and distributed solar PV and the relative lack of response from thermal generation, the NEM is currently substantially oversupplied with capacity. This is particularly true of New South Wales and Victoria.

To meet the LRET, the market is required to continue to make significant investments in renewable generation. Although wind generation is not comparable to thermal generation in terms of its contribution to reliability, substantial wind generation does reduce the need for thermal generation. ROAM has not enforced an assumed contribution of wind generation to peak demand. Rather, ROAM uses observed generation and demand patterns from the past five historical financial years. This method allows the contribution of wind generation to peak demand to change over time and to reflect the forecast geographical diversity of wind generation. ROAM observed that the contribution of large-scale renewable generation capacity to peak demand varies between regions, reference years and over time. The contributions observed in the modelling range from 3% to 62% of capacity. The average contribution is approximately 24%.

To achieve a market in which the USE is approximately meeting the reliability standard, ROAM has withdrawn over 8.6 GW of capacity across the NEM. Table 5.1 illustrates the level of thermal retirement/mothballing and the additional investment in renewable generation that occurs by 2016-17.

Table 5.1 – Capacity Changes – 2016-17

	Queensland	New South Wales	Victoria	South Australia
Thermal Retirement (MW)	1,316	3,796	2,784	706
Additional Renewable Capacity (MW)	225	1,443	1,237	603

This market has a level of reserve that is much lower than has ever been observed over an extended period in the NEM. Furthermore, the low level of reserve exists in each region simultaneously. A market in which the level of USE is expected to achieve the reliability standard experiences significant price volatility. The majority of existing baseload and intermediate generators are observed to earn significant revenue in excess of assumed fixed and variable costs. The pool prices observed in the Base Case, after adjusting for MPC and CPT are provided in Figure 5.1; an MPC of $9,000/MWh and a CPT of $135,000 have been used to produce these indicative outcomes.

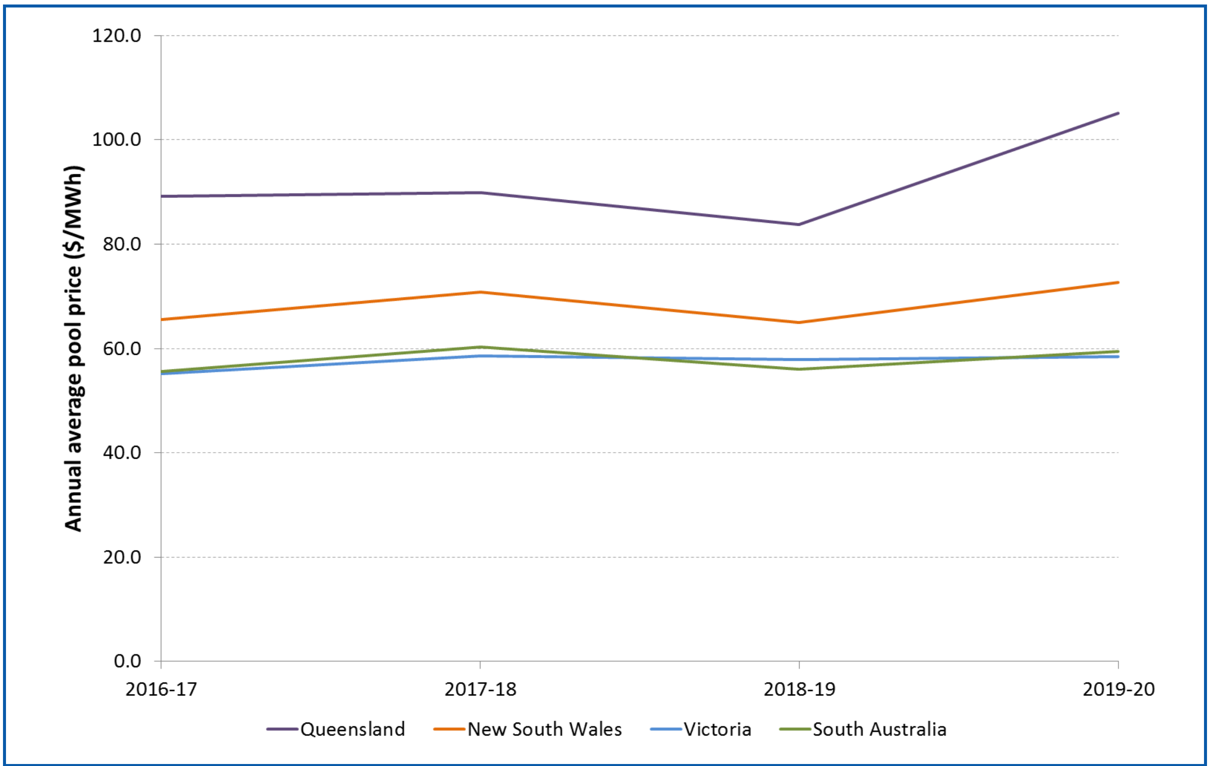

Figure 5.1 – Annual Average Pool Prices – Stage 1 Base Case – MPC of $9,000/MWh, CPT of $135,000

5.1.2 Results

Cap Defender Approach

Figure 5.2 shows the MPC required[17] to achieve the reliability standard in each region.

[17] The MPC incorporates an assumed 15 times multiplier for the CPT. The relationship between this multiplier and the MPC is analysed in Section 5.3.

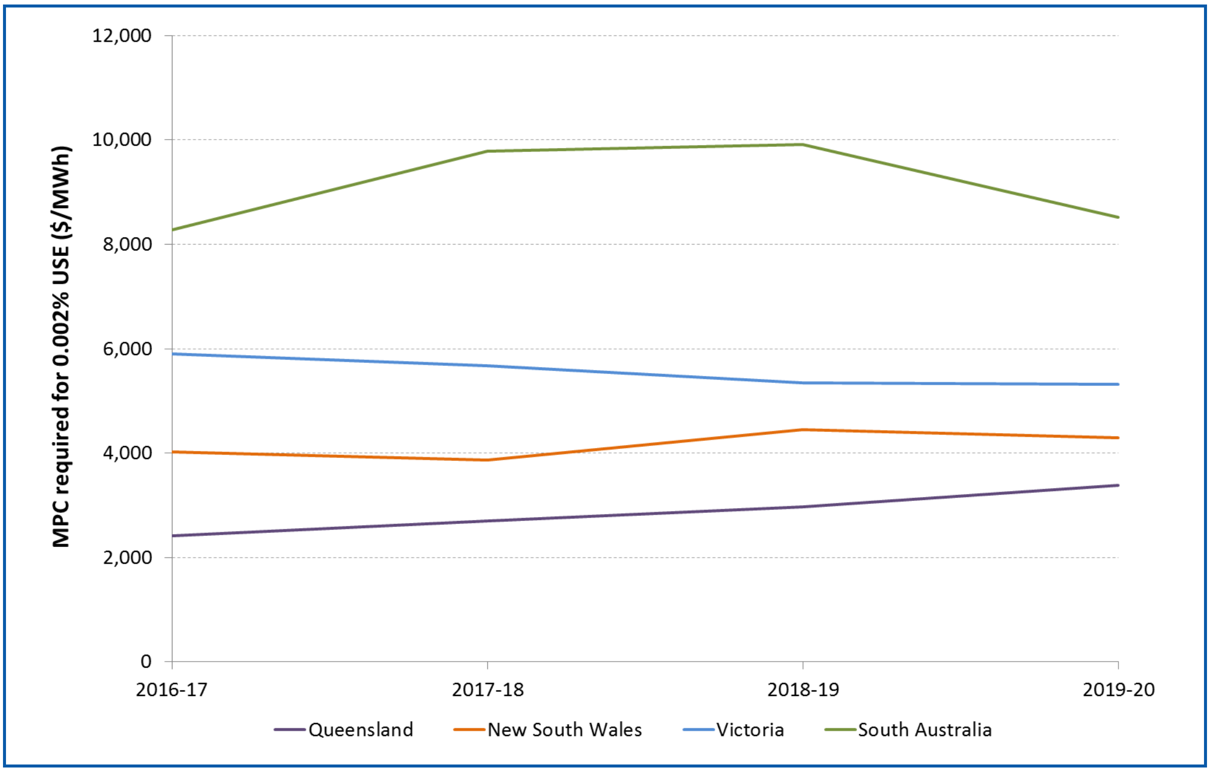

Figure 5.2 – MPC Results – Stage 1 Base Case

The relationships between MPC and USE in each region are provided in Figure 5.3. The results in Figure 5.2 are determined by calculating the intercept of these regional relationships with the reliability standard.

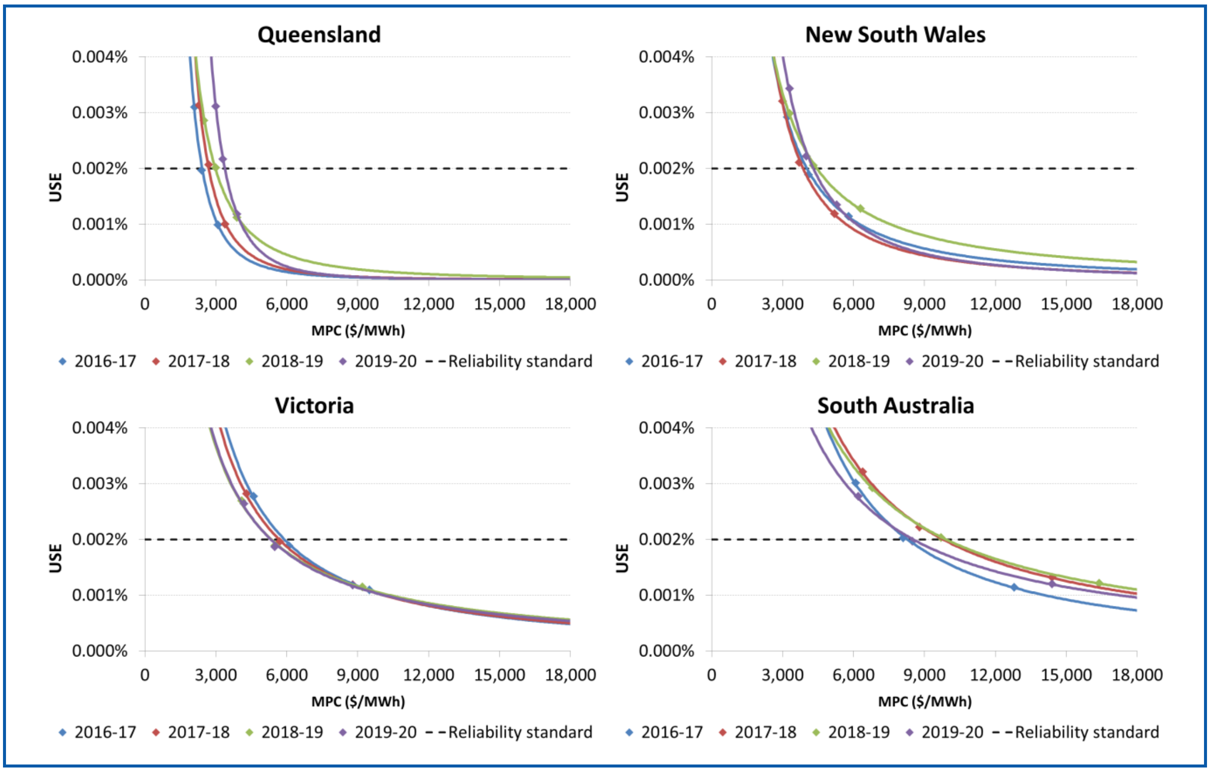

Figure 5.3 – MPC and USE Relationship in Each Region – Stage 1 Base Case

Extreme Peaker Approach

The results of the extreme peaker approach are provided in Figure 5.4. The average of all regions (all regions are equally weighted) is also provided for comparison with the 2010 Review. The complete dataset used to determine the MPC required to achieve the reliability standard in each region in 2018-19 is provided in Figure 5.5.

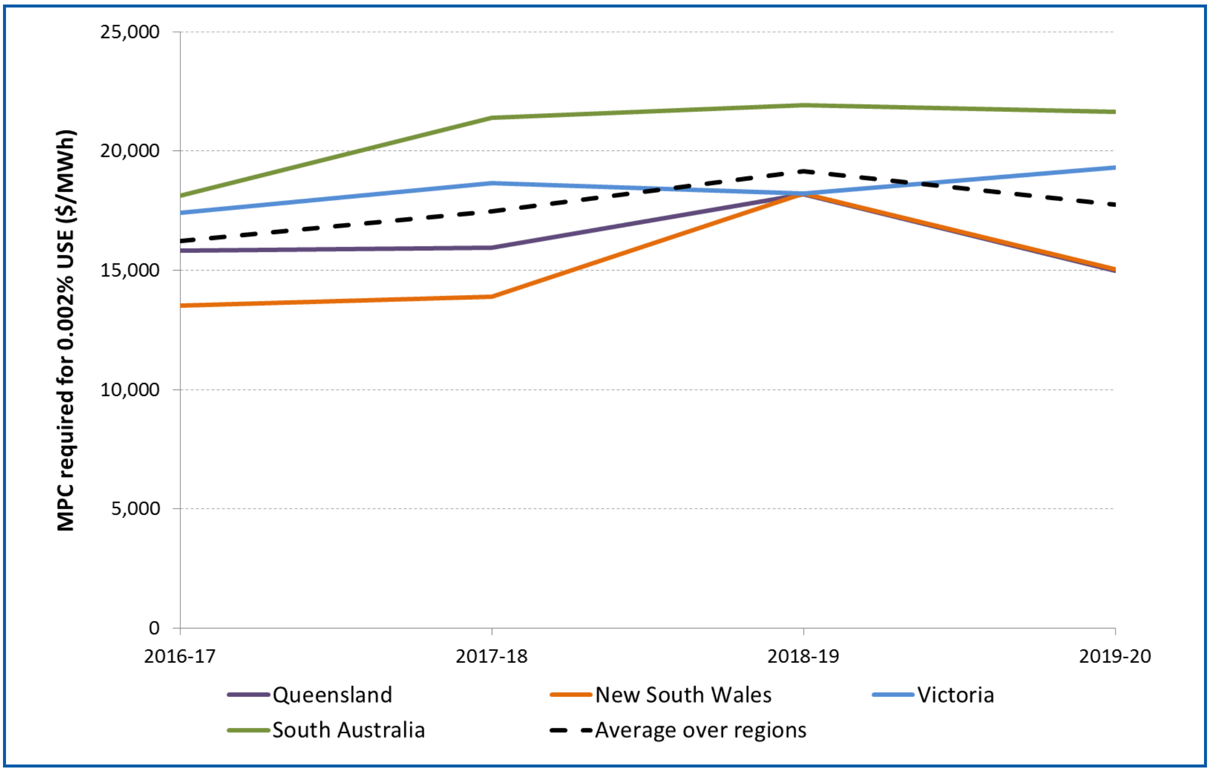

Figure 5.4 – MPC Results – Stage 1 Base Case Extreme Peaker

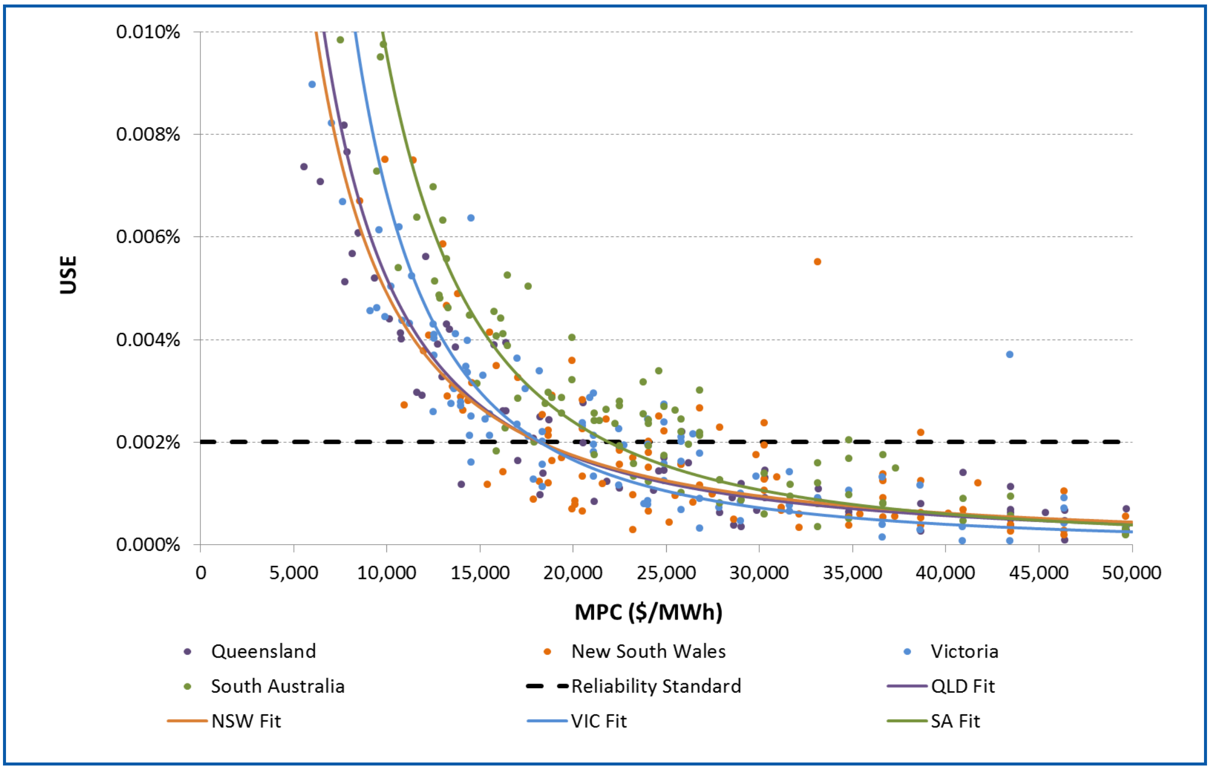

Figure 5.5 – Iteration Data – Stage 1 Base Case Extreme Peaker – 2018-19

5.1.3 Analysis

It is evident that significant differences in MPC requirements are observed between regions when the cap defender approach is applied. In particular, South Australia requires an MPC which is significantly higher than other regions to allow a new entrant OCGT to operate profitably in a market which is expected to achieve the reliability standard. ROAM has conducted detailed analysis of these results to determine the characteristics of each region that are related to the MPC requirement. A summary of this analysis is presented below.

A caveat that should be considered when interpreting these results is that pool price outcomes were post-processed to apply a different MPC and CPT to all regions simultaneously. This means that, for example, the impact of a lower MPC in Queensland (and its associated impact on investment incentives) was not taken into account when determining the revenue of the cap defender in New South Wales. Consideration of different MPCs in each region is beyond the scope of this review.

Post-processing of market price outcomes also means that inputs such as portfolio contracting levels and their associated impact on bidding strategies, the volume of DSP and cap contract premiums or discounts were not changed as the MPC was adjusted. The impact of the MPC on these variables is difficult to assess using a quantitative, systematic approach. Whilst such an approach may be achievable, time constraints restricted ROAM from completing more in depth analysis in this respect.

Pool Prices

The MPC calculations provided above are an outcome of the level of pool price volatility observed in the market simulations. Figure 5.6 illustrates the distribution of pool prices in each region in 2016-17. These pool prices are from the market simulations with an MPC of $13,100/MWh and do not incorporate the application of an alternate MPC or any CPT. The market factors which drive these outcomes (which are indicative of those observed in each year of the study) are analysed in detail in this section. The pool price figure below shows that there are considerable differences between the regions at prices between $300/MWh and the MPC. However, the USE outcomes between these regions are comparable, with all regions approximately achieving the reliability standard.

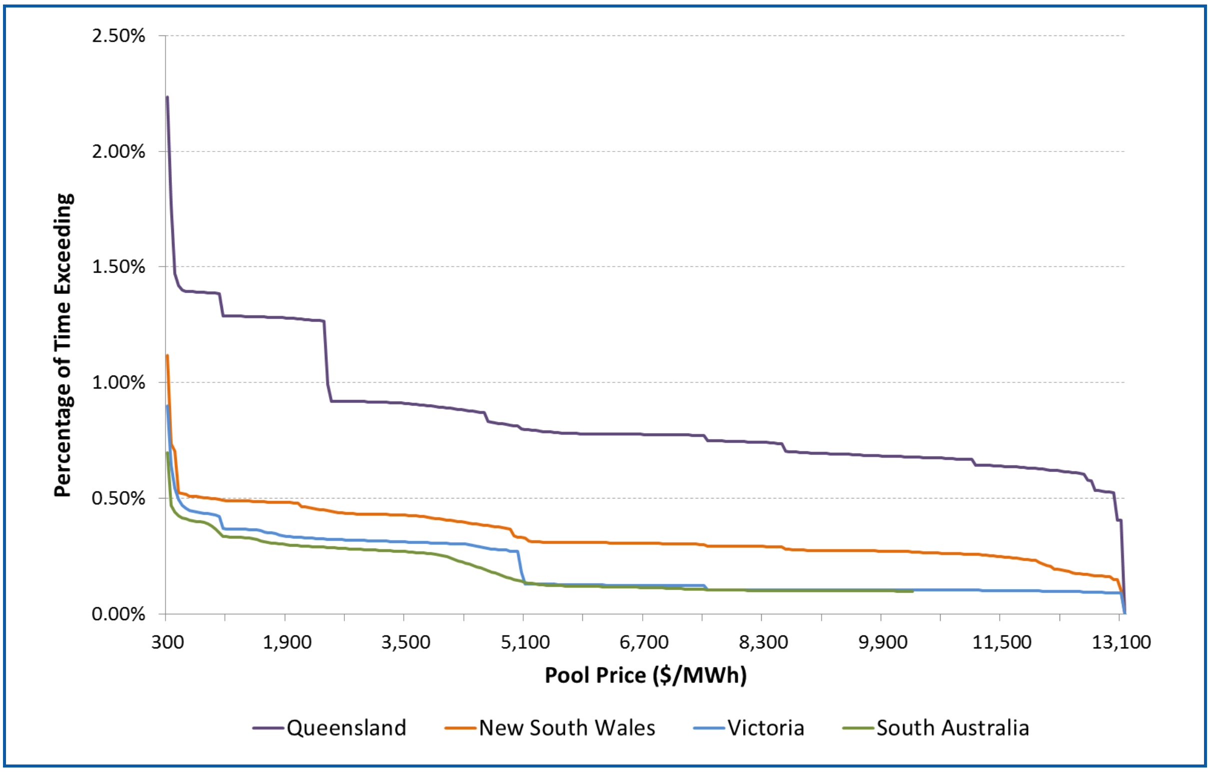

Figure 5.6 – Pool Price Duration Curves – Stage 1 Base Case – 2016-17

Loss of Load Probability and Loss of Load Expectation

The Loss of Load Probability (LOLP) is the percentage of time during which USE is occurring. LOLP does not consider the magnitude of USE during these periods. Loss of Load Expectation (LOLE) is a similar measure that converts LOLP to an expected number of hours. Both LOLP and LOLE are used in reliability assessments in international jurisdictions.

All regions exhibit a comparable LOLP (Table 5.2) and LOLE (Table 5.3). The values are slightly higher in Queensland and lower in South Australia indicating there are fewer USE events in South Australia than Queensland. However, since all regions have approximately 0.002% USE, USE events in South Australia must also be deeper relative to total energy consumption.

Table 5.2 – LOLP – Average of All Reference Years – Stage 1 Base Case

	Queensland	New South Wales	Victoria	South Australia
2016-17	0.051%	0.042%	0.041%	0.038%
2017-18	0.055%	0.049%	0.040%	0.038%
2018-19	0.047%	0.039%	0.039%	0.034%
2019-20	0.054%	0.050%	0.037%	0.031%

Table 5.3 – LOLE (hours) – Average of All Reference Years – Stage 1 Base Case

	Queensland	New South Wales	Victoria	South Australia
2016-17	4.5	3.7	3.6	3.3
2017-18	4.8	4.3	3.5	3.3
2018-19	4.1	3.5	3.4	3.0
2019-20	4.8	4.4	3.3	2.8

Load Factor

It is a requirement of the Stage 1 modelling that each region has sufficient capacity to achieve an average volume of USE that is equivalent to the reliability standard. This requirement is primarily related to the magnitude of peak demand in each region. However, the ratio of average demand to peak demand in each region exhibits substantial disparity. As a result, the amount of installed capacity relative to average demand differs significantly between regions. ROAM has conducted detailed analysis of regional demand. ROAM proposes that it is “net demand” which is most informative in this analysis[18]. Net demand allows for the consideration of the level of renewable generation installed in each region. Renewable generation in this context includes generation that is assumed to bid at zero or negative prices, i.e. wind and solar. Given this bidding behaviour, renewable generation effectively acts to reduce demand from the perspective of a shoulder or peaking generator.

Load factor is defined as average demand divided by the demand at time of peak. Load factors are provided for both market demand and net demand in Table 5.4 and Table 5.5 respectively.[19] All load factors are calculated for the 10% POE demand forecast. It is evident from Table 5.4 that South Australia has a load factor which is well below other mainland regions. When the penetration of renewable generation is considered, this difference increases significantly.

The MPC calculation in the cap defender approach is driven by market outcomes. These market outcomes are strongly related to the demand in all periods, but particularly those in periods of relatively high demand. Assuming that other factors are held constant, a lower load factor indicates that demand in periods other than the regional peak will be reduced and therefore indicates that pool prices will be reduced. A reduction in pool prices will tend to reduce the revenue earned by the cap defender and therefore results in a requirement for a higher MPC. Therefore, South Australia’s low load factor contributes to the high MPC requirement calculated in this modelling.

[18] Net demand refers to only demand that will be met by generators in the market other than wind and solar, assuming that all renewable generation is dispatched before thermal generation.

[19] Market demand refers to the demand that is expected to be met by scheduled, semi-scheduled and significant non-scheduled generators. Market demand is already net of rooftop PV.

Similarly, Queensland is observed to have a high load factor; this is driven by a relatively low penetration of renewable generation and significant growth in industrial load resulting from LNG production and transportation. The order of the load factors provided below is consistent with the MPC calculations in Figure 5.2 and the pool price outcomes provided in Figure 5.6.

Table 5.4 – Load Factor – Market Demand – Average of All Reference Years – Stage 1 Base Case

	Queensland	New South Wales	Victoria	South Australia
2016-17	68%	58%	55%	45%
2017-18	67%	58%	55%	44%
2018-19	66%	57%	55%	43%
2019-20	66%	57%	54%	44%

Table 5.5 – Load Factor – Net Demand – Average of All Reference Years – Stage 1 Base Case

	Queensland	New South Wales	Victoria	South Australia
2016-17	68%	57%	53%	30%
2017-18	67%	55%	51%	27%
2018-19	65%	53%	51%	24%
2019-20	65%	52%	50%	22%

The load factor is indicative of the volume of surplus generation which may exist in an average demand period given that a region must have sufficient capacity to meet peak demand. Of potentially greater relevance to the cap defender is the level of demand associated with the 95th percentile[20] in each region. In each reference year, the level of demand has been calculated which corresponds to the top 5% of demand periods; this calculation has been performed for both market demand and net demand. This value is compared with the absolute peak demand in each region. These results are provided in Table 5.6 and Table 5.7 and are consistent with the load factor results provided above. South Australian demand declines rapidly and has a very narrow peak compared to the other mainland regions. As a result, the frequency of revenue opportunities for the cap defender in South Australia is diminished. This effect is exacerbated by the impact of the increased renewable penetration in the region.

[20] The 95th percentile being indicative of a relatively high demand period in which peaking generation may be required to operate.

Table 5.6 – 95th Percentile Demand / Peak Demand – Market Demand – Average of All Reference Years – Stage 1 Base Case

	Queensland	New South Wales	Victoria	South Australia
2016-17	82%	75%	70%	64%
2017-18	82%	75%	70%	63%
2018-19	80%	74%	70%	62%
2019-20	81%	74%	70%	63%

Table 5.7 – 95th Percentile Demand / Peak Demand – Net Demand – Average of All Reference Years – Stage 1 Base Case

	Queensland	New South Wales	Victoria	South Australia
2016-17	82%	76%	71%	58%
2017-18	81%	74%	71%	56%
2018-19	80%	73%	71%	55%
2019-20	80%	73%	70%	55%

Energy Limited Generation

The operation of hydro generation assets has been found to be a significant factor in the calculation of MPC. In the volatile pool price market modelled in this study, hydro generators are required to schedule capacity to high price bands to ensure that water limits are not violated. This is particularly true of pumped storage schemes which have relatively short-term storage.

There is approximately 5.7 GW of hydro capacity in the mainland regions of the NEM; hydro generation is located in New South Wales, Victoria and Queensland. The generation of these assets in the modelling is restricted to a level consistent with expected annual inflow. These inflows are generally insufficient to allow hydro generation to operate with a high capacity factor. As an aggregate, mainland hydro assets operate with an annual capacity factor of approximately 11%. Hydro generators therefore withhold to relatively high price bands to maximise their revenue given restrictions on annual and seasonal generation.

The scheduling of generation by hydro generators will increase price volatility and therefore result in additional revenue for the cap defender. Although limited on an energy basis, hydro generation has a contribution to peak demand that is close to 100%. However in contrast to a baseload generator bidding at near its SRMC, a hydro unit bidding at prices above $300/MWh will provide additional revenue opportunities for the cap defender.

South Australia has no hydro generation. This contributes to the requirement of a high MPC to install a profitable peaking generator. The majority of generation in South Australia has an SRMC below $150/MWh and will therefore only withhold when it is beneficial from a portfolio perspective. However in other mainland regions, hydro generation units are bidding substantial capacity at prices between $300/MWh and the MPC.

Pumped hydro schemes with relatively short-term storage are particularly influential in this analysis. The largest such scheme is the Wivenhoe Power Station in Queensland[21]. The recoverable energy stored in the Split Yard Creek dam is sufficient for only five hours of generation at full capacity. In this analysis, ROAM has applied a conservative approach to modelling the operation of Wivenhoe. To minimise the occurrence of USE, Wivenhoe is assumed to bid at the MPC. This approach attempts to negate the possibility that Wivenhoe exhausts its stored energy in periods of moderate prices and can therefore not operate in periods of MPC and possibly USE.

This approach to modelling Wivenhoe is conservative from the point of view that it results in the lowest possible level of USE while also applying no downward pressure on pool prices. Therefore, this operation creates additional revenue opportunities for the cap defender than would be observed if the Wivenhoe Power Station were replaced with an equivalent amount of thermal capacity. The effect of Wivenhoe can be observed in Figure 5.6 which shows that prices are at the MPC more regularly than in any other region. The same behaviour is observed for the Shoalhaven Scheme although the effect is reduced given the relative size of the scheme compared to regional peak demand in New South Wales.

Therefore, the presence of substantial hydro generation in New South Wales, Victoria and Queensland is a contributing factor to the reduced MPC required to achieve the reliability standard when compared to South Australia. The relatively short-term storages in the Wivenhoe and Shoalhaven schemes in particular result in a material reduction in the required MPC.

Interconnection

The differences in the MPC required in each region result from pool price differences in the market simulations. With unlimited interconnection, pool price separation between regions would be limited to the impact of inter-regional transmission losses. The pool price outcomes illustrated in Figure 5.6 exhibit considerable pool price differentiation. This indicates that interconnection is frequently constrained in periods of pool price volatility.

[21] Tumut 3 in New South Wales is significantly larger than Wivenhoe Power Station. However, Tumut 3 has a larger storage and is also supplied from the outflow of Upper Tumut. Therefore, Tumut 3 has sufficient storage ability to operate for an extended period of time relative to Wivenhoe and Shoalhaven.

Pool price volatility is most frequently observed in Queensland. Other regions in the NEM are rarely able to "import" these high prices as the ability to export energy from New South Wales to Queensland is relatively low. ROAM has not considered the impact of a potential QNI upgrade in this analysis. Any QNI upgrade would result in a greater convergence between Queensland and New South Wales and to a lesser extent, Victoria and South Australia. Queensland import capacity, as a percentage of regional demand, is far lower than any other region in the NEM. This reduction in competition from other regions allows Queensland portfolios to more frequently obtain benefit from exercising transient market power. The strategic withholding of capacity from the existing generation portfolios creates additional revenue opportunities for new entrant peaking generation which contributes to the low MPC requirement in Queensland.

Despite a relatively large interconnector, price separation is also regularly observed to occur between Victoria and New South Wales. Figure 5.7 illustrates that periods of large pool price separation occur when the VIC1-NSW1 interconnector is at a binding import or export limit. This restricts the ability of each region to import periods of high price across this interconnector. Therefore, although the nominal size of the VIC1-NSW1 interconnector is large, its ability to allow prices in Victoria and New South Wales to converge is limited due to:

- The relative size of demand in Victoria and New South Wales in comparison to the size of the interconnector; and
- The binding of intra-regional transmission constraints which limit flow between the physical regional boundary and the reference node in each region, thereby restricting flow between regions.

The operation of the large hydro stations, Tumut and Murray are also very influential on the ability of VIC1-NSW1 to transfer energy. Figure 5.7 shows that the interconnector often binds in periods of low transmission flow; export capacity can be constrained to a southerly flow in periods of very high Tumut operation.

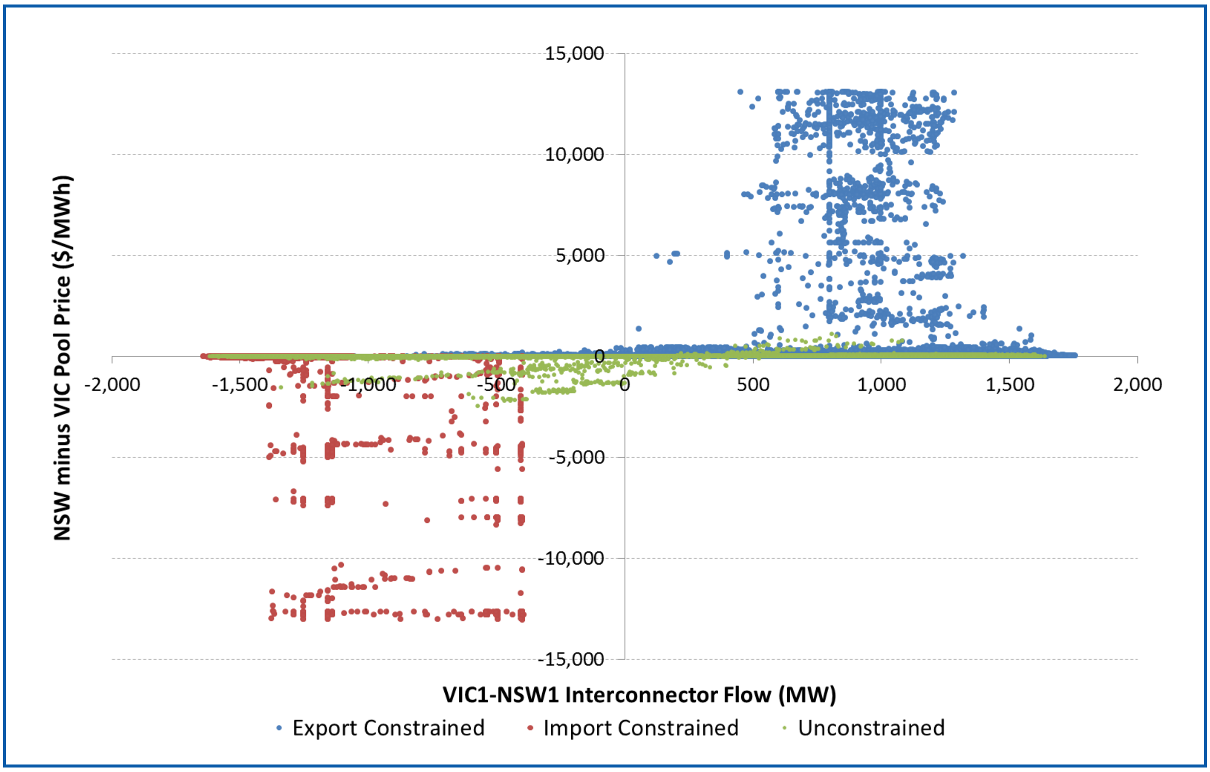

Figure 5.7 – Victoria – New South Wales Pool Price Separation – Stage 1 Base Case – 2018-19

The difference in MPC outcomes between Victoria and South Australia is heavily influenced by the correlation of demand and renewable generation between the two regions. Analysis of dispatch outcomes indicates that South Australia is frequently prevented from importing high Victorian pool prices because flow from South Australia to Victoria is at its maximum limit.

Figure 5.8 illustrates the net demand in Victoria as a percentage of peak demand against the price differential between Victoria and South Australia. This figure shows only the 5% of periods with highest South Australian net demand. The fact that the majority of points lie toward the right of the chart indicates that periods of high South Australian net demand frequently coincide with periods of high Victorian net demand. As a result, pool prices in both regions during these periods are high, price differences between the two regions are low and interconnector flow between Victoria and South Australia is rarely at its limit. Consequently, periods with large price separation between Victoria and South Australia due to interconnector flow being at its maximum limit are infrequent in periods of high South Australian demand.

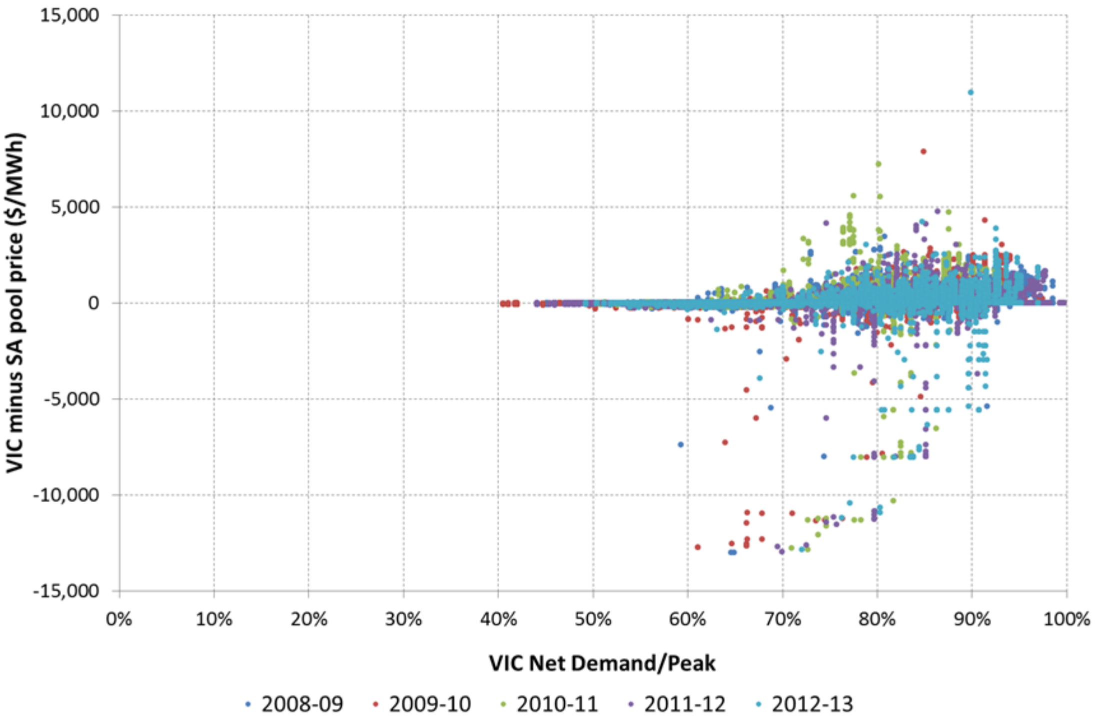

Figure 5.8 – Price Separation During Periods of High South Australian Demand[22] – Stage 1 Base Case – 2016-17

Figure 5.9 shows the net demand in South Australia as a percentage of peak demand against the price difference between South Australia and Victoria in the 5% of periods with highest Victorian net demand. There is a large spread in South Australian demand (spread along the x-axis) in periods of high Victorian demand, in contrast to the situation illustrated in Figure 5.8.

[22] Results are presented for the five reference years.

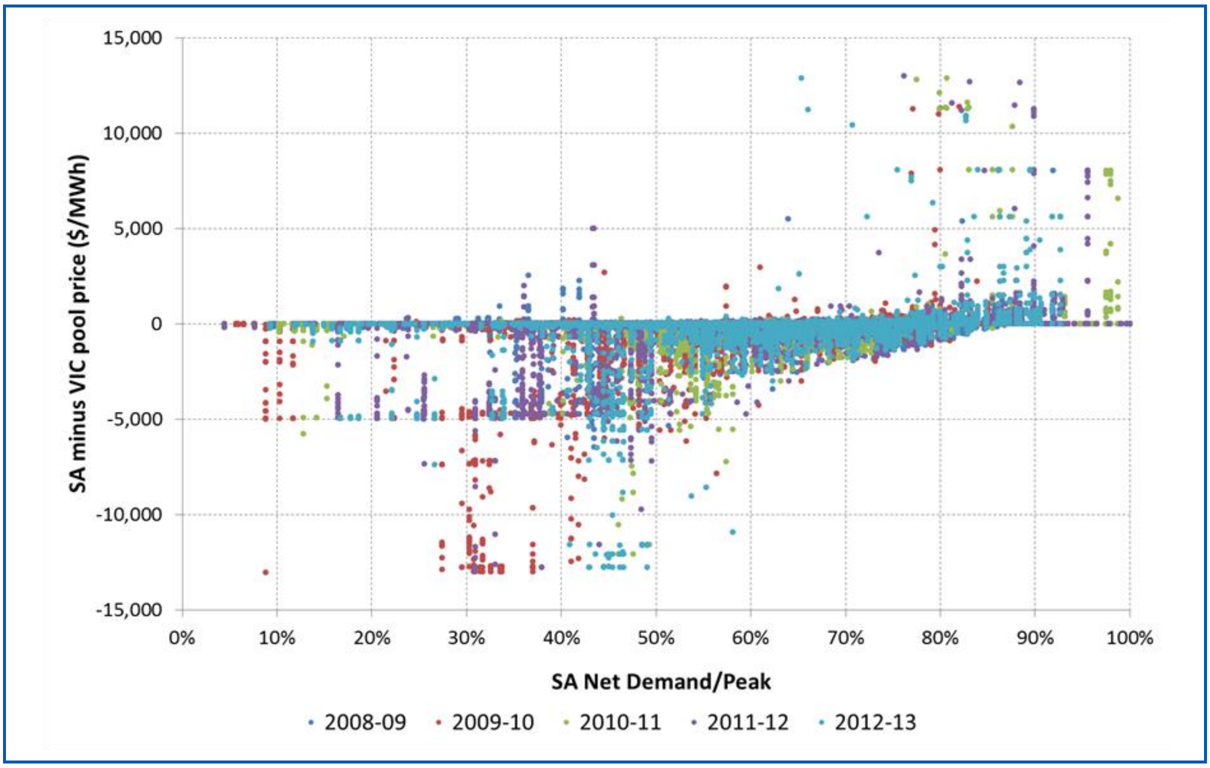

Figure 5.9 – Price Separation During Periods of High Victorian Demand – Stage 1 Base Case – 2016-17

The difference in spread along the x-axis between Figure 5.8 and Figure 5.9 relates to the relative impact of wind on net demand in the two regions. Both demand and wind generation in South Australia and Victoria are moderately correlated. Periods of high net demand in Victoria are characterised by having a high level of market demand due to the size of Victorian demand relative to the installed capacity of wind generation. However, these periods may also exhibit a high level of wind generation in both South Australia and Victoria. Therefore, when Victoria has high net demand, the net demand in South Australia may be significantly below peak levels.

Of particular note are the points to the left of Figure 5.9 which correspond to periods where Victorian demand is high but South Australian demand is low. In these periods, South Australian prices are low, Victoria imports energy from South Australia to the interconnector limits causing Victorian price to separate from the South Australian pool price.

Overall, Figure 5.8 and Figure 5.9 demonstrate that pool price separation is asymmetric between South Australia and Victoria. Pool price separation between the two regions most frequently occurs when the pool price in Victoria exceeds the price in South Australia. As a result, the cap defender in South Australia has lower pool revenue than the cap defender in Victoria and therefore requires a higher MPC to operate profitably.

Extreme Peaker Analysis

Figure 5.4 demonstrates that the extreme peaker approach results in a markedly different outcome compared with the equivalent cap defender results provided in Figure 5.2. The most significant difference between the two approaches is that the cap defender allows the new entrant to recover its capital investment in periods in which the price is below the MPC. The extreme peaker is prevented from benefiting from these opportunities. Therefore, the cap defender approach incorporates a range of market characteristics which have no bearing on the extreme peaker outcomes. This difference allows the cap defender to operate profitably with a significantly lower MPC than is required by the extreme peaker.

The extreme peaker results also exhibit a higher degree of convergence between the regions. The MPC calculated in the extreme peaker approach is an outcome that primarily relates to the shape of USE. Shape in this instance refers to the numbers of hours of MPC that are expected if the reliability standard is exactly met. Therefore the market oriented factors such as load factor and energy limited generation that drive the differences in the cap defender results have no impact in the extreme peaker analysis.

Figure 5.10 illustrates the shape of the USE duration curve in each region in 2016-17 for the 2008-09 reference year. This graphic shows a material level of divergence between the four mainland NEM regions. Figure 5.11 shows the shape of the USE duration curve when considering all five of the historical reference years. The y-intercept of this curve is reflective of the primary driver on the MPC results observed in Figure 5.4. This figure illustrates the consideration of multiple reference years results in a comparable number of hours of USE in each of the mainland NEM regions where all regions are at the reliability standard. As a result, the MPC calculated by the extreme peaker method is similar for all regions.

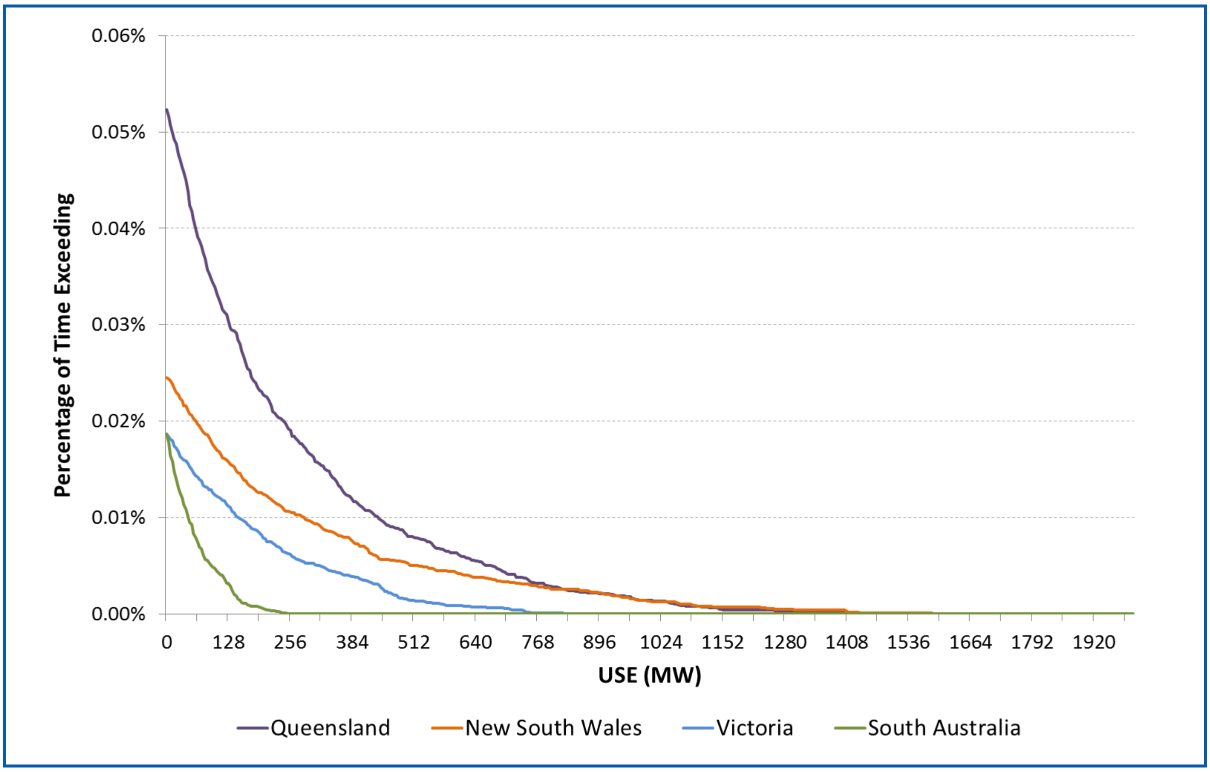

Figure 5.10 – USE Duration Curves – 2008-09 Reference Year – Stage 1 Base Case – 2016-17

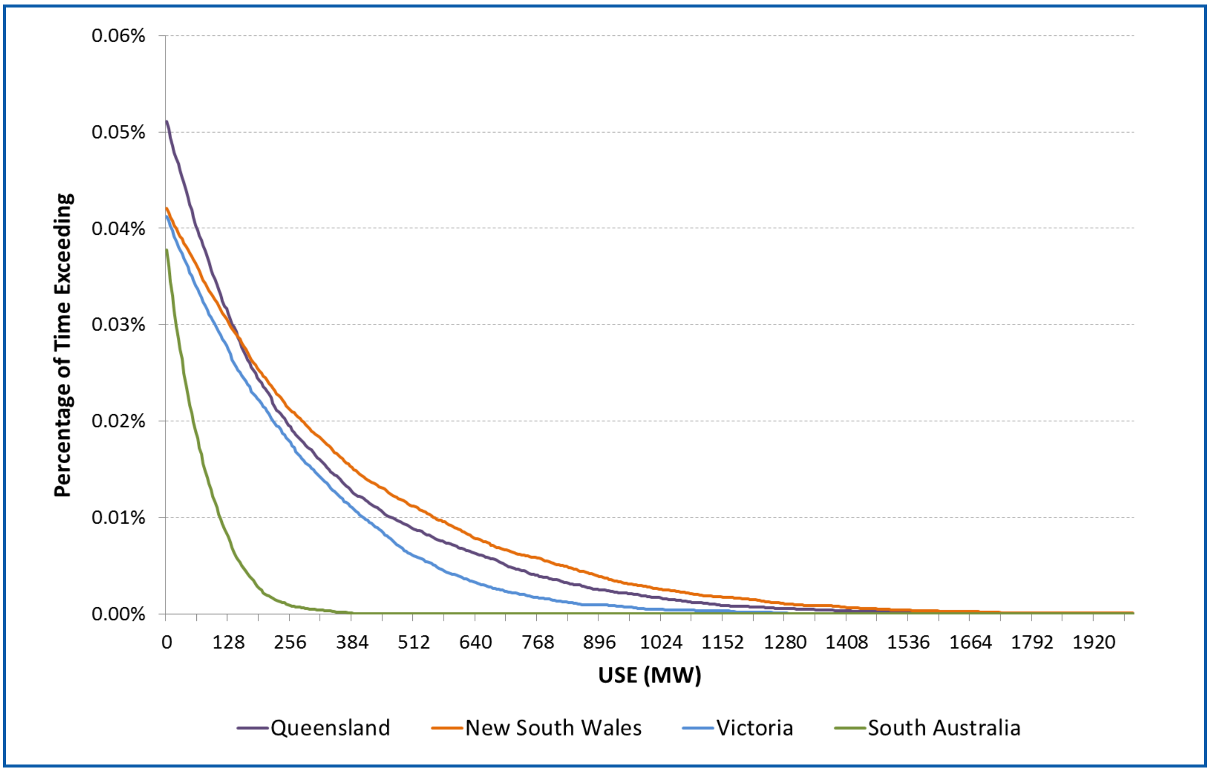

Figure 5.11 – USE Duration Curves – Average of all Reference Years – Stage 1 Base Case – 2016-17

5.2 OCGT Capital Cost Sensitivity

ROAM has analysed the impact of the assumed capital cost for the new entrant peaking generator on the MPC required to achieve the reliability standard. This sensitivity uses the same simulated market dispatch as the Base Case, but a higher or lower capital cost in the determination of the MPC required for the new entrant generator to profitably operate. The results of this analysis are provided in Figure 5.12.

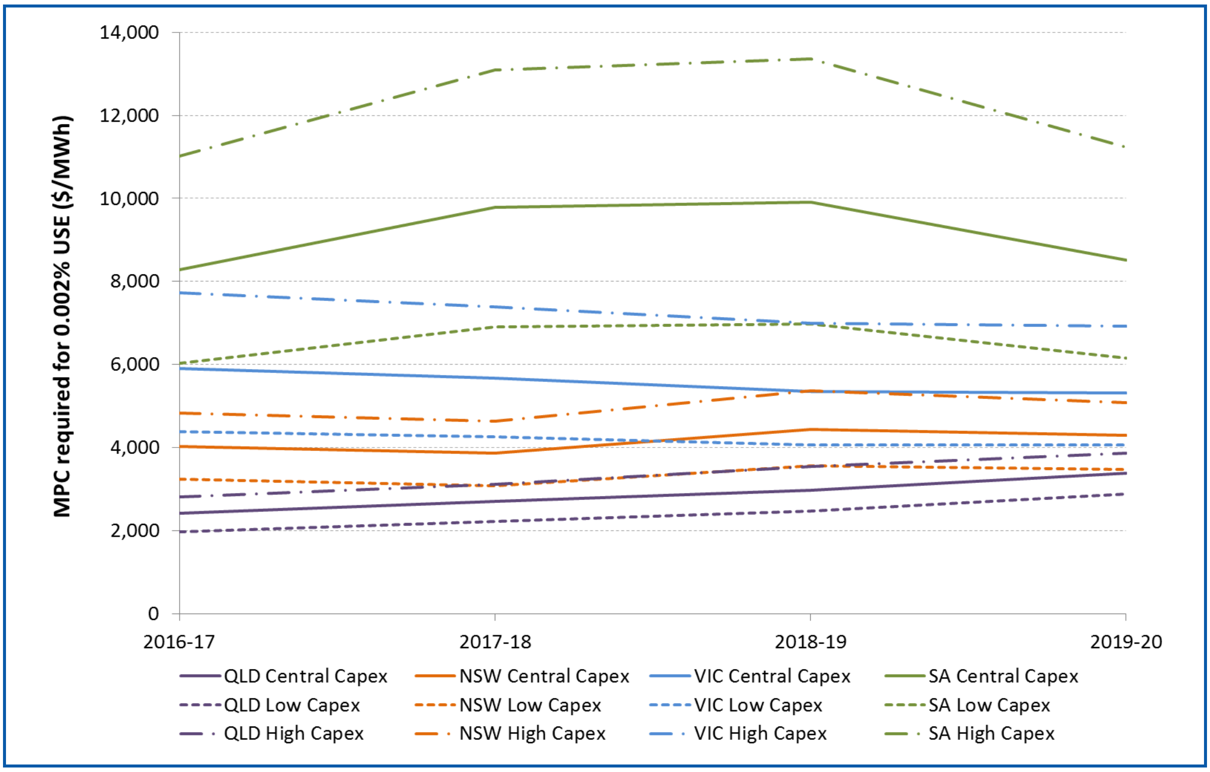

Figure 5.12 – Effect of Capital Cost on MPC Results – Stage 1

As capital cost increases, the generator needs to recoup higher fixed costs, so the MPC required increases. A 20% decrease in annualised capital cost from $100,000/MW/annum to $80,000/MW/annum gives a 22% decrease in the MPC averaged over regions and study years. On the other hand, a 20% increase in annualised capital cost from $100,000/MW/annum to $120,000/MW/annum requires a 25% increase in the MPC averaged over regions and study years.

5.3 CPT Sensitivity

The value of the CPT has a material impact on the MPC required to achieve the reliability standard. Currently, the CPT is set to 15 times the value of MPC. ROAM analysed the impact of changes to this multiplier, using the same simulated market dispatch as the Base Case. Two alternative CPT multipliers (12 and 18 times the MPC) are applied in the determination of the MPC required for the new entrant generator to profitably operate. Figure 5.13 illustrates the results of this analysis.

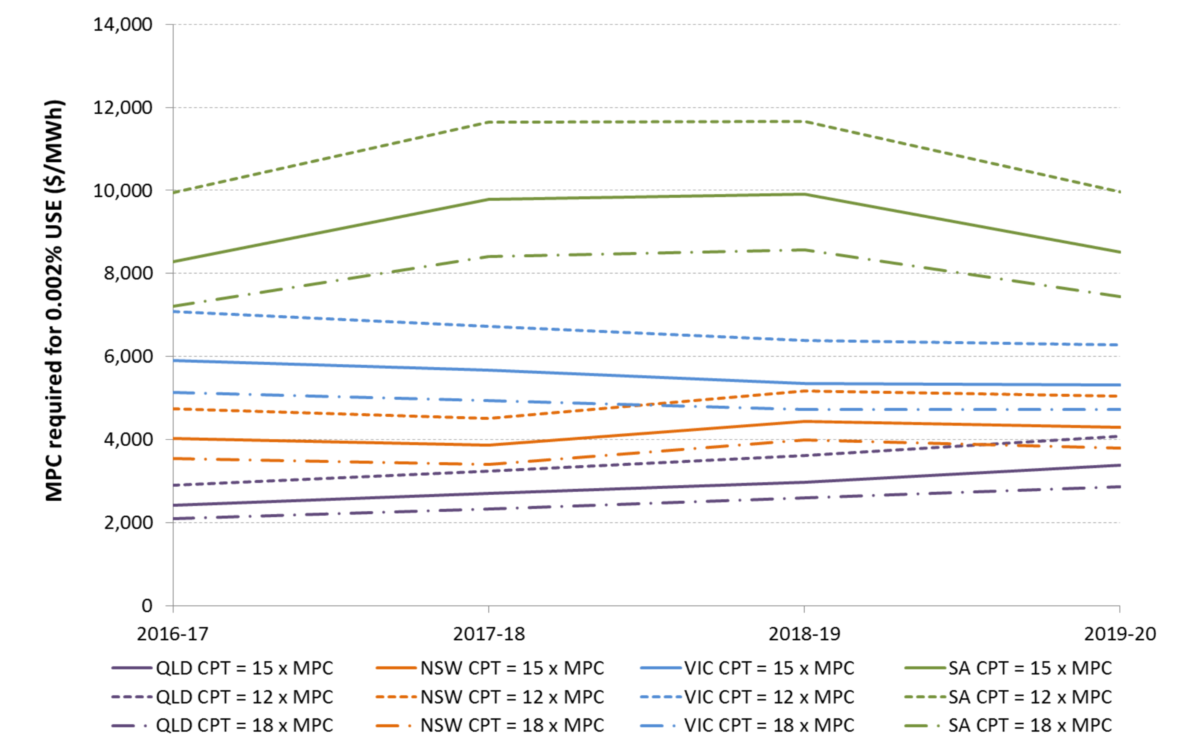

Figure 5.13 – Effect of CPT Multiplier on MPC Results – Stage 1

As the CPT increases, the number of administered price periods decreases leading to fewer APC-adjusted periods. As a result, the pool revenue of the new entrant OCGT increases and the MPC required for a new entrant OCGT to operate profitably decreases. Averaged over regions and study years, a 25% decrease in CPT multiplier from 15 to 12, leads to a 19% increase in required MPC. A 25% increase in CPT multiplier from 15 to 18 decreased the MPC required by 13%.

This analysis demonstrates that there is a clear relationship between the MPC and the CPT. Given that the CPT is frequently invoked in a market which is just achieving the reliability standard, an increase in the CPT increases the revenue earned by the cap defender and therefore, decreases the MPC requirement. The CPT should be related to a view of the acceptable level of risk for market participants, one element of which is prudential requirements as outlined in Section 9.1.6.

5.4 Carbon Price Sensitivity

To determine the sensitivity of results to the carbon price, ROAM analysed the MPC required if the carbon price remains at the Treasury Core Trajectory (see Section 4.6.4). In this modelling, the generator planting schedule remained the same as the Base Case. The alternative carbon price influenced dispatch outcomes and therefore resulted in different pool price outcomes. The resulting MPC required for a new entrant OCGT to operate profitably is shown in Figure 5.14.

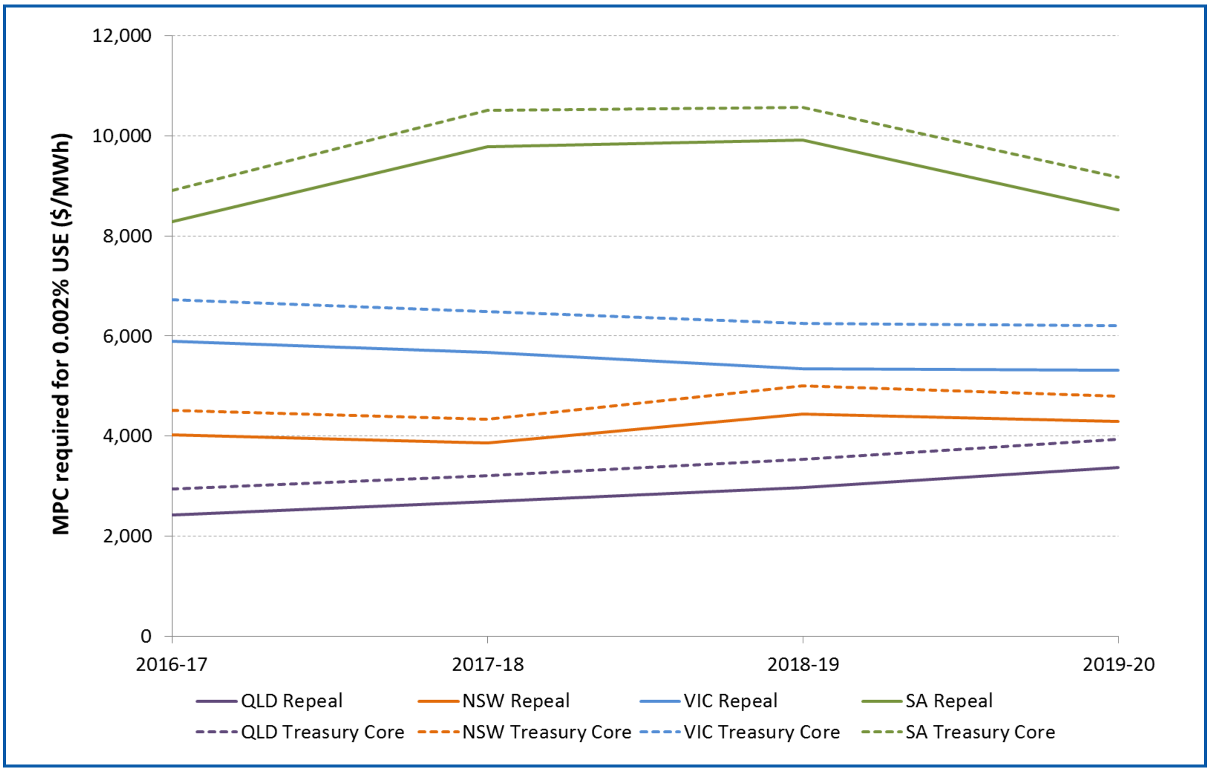

Figure 5.14 – Effect of Carbon Price on MPC Results – Stage 1

Overall, the higher carbon price increases the required MPC. The key driver of this effect is that the slightly higher pool prices cause the APC to be applied more frequently (Figure 5.15). This decreases pool revenue for the new entrant OCGT so that the MPC required increases. In addition, the slightly higher SRMC of the OCGT under the Treasury Core carbon price also acts to decrease profitability.

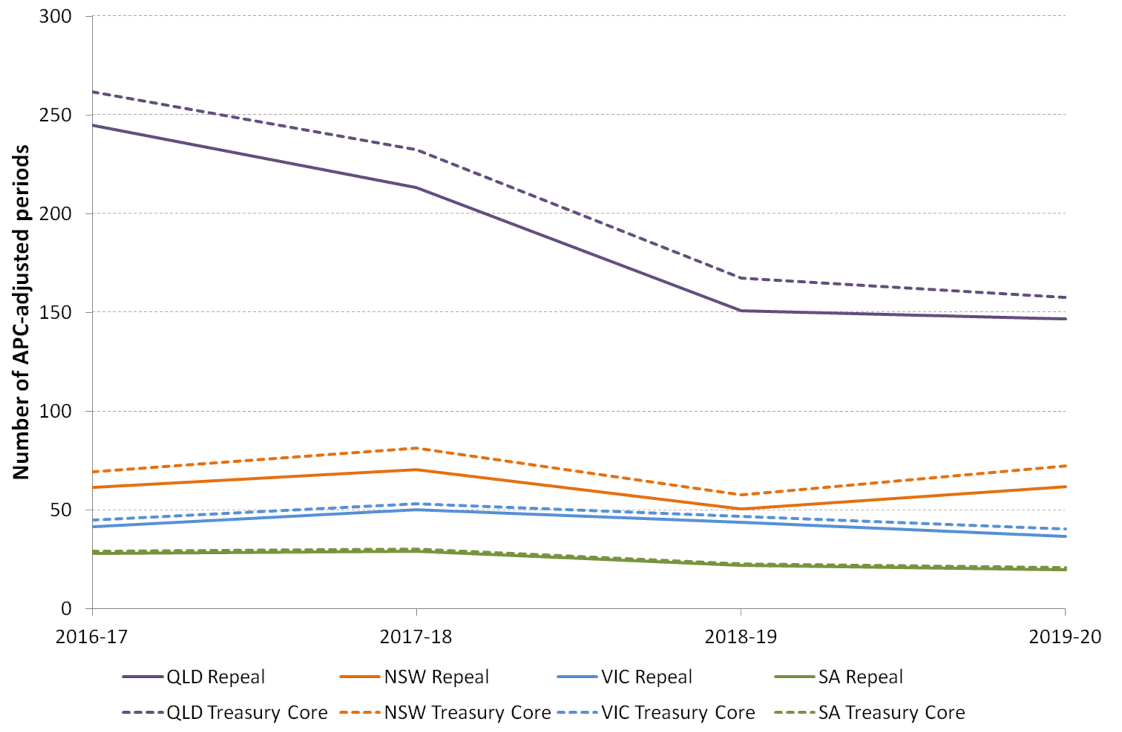

Figure 5.15 – Number of APC-Adjusted Periods – Stage 1 Base Case and Carbon Price Sensitivity

5.5 Gas Price Sensitivity

Given the uncertainty surrounding future gas prices in the NEM, ROAM assessed the sensitivity of the MPC required to deliver the reliability standard to the gas price. As an alternative scenario, ROAM used a Low Gas trajectory where prices are between 2-3.5 $/GJ cheaper than in the Base Case in the period 2016-17 to 2019-20 (see Section 4.6.3).

Similarly to the Carbon Price sensitivity, in this modelling the generator planting schedule remained the same as the Base Case. The altered gas price resulted in different dispatch and pool price outcomes. The resulting MPC required for a new entrant OCGT to operate profitably is shown in Figure 5.16.

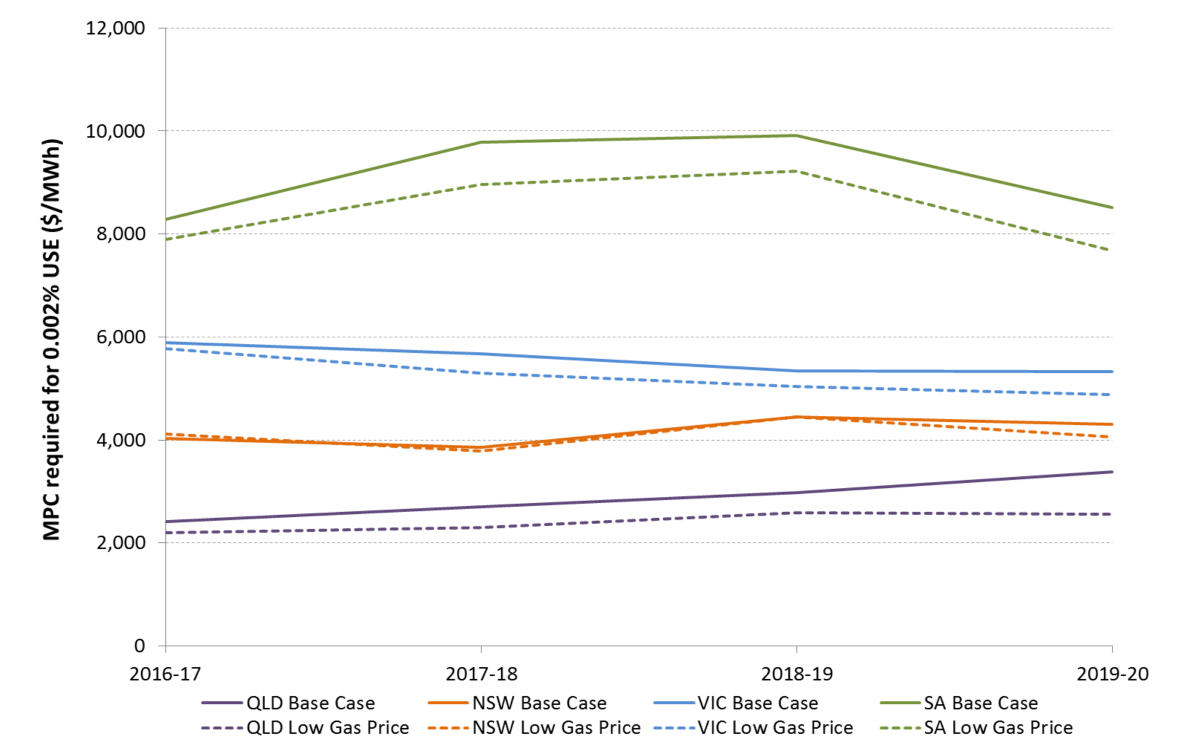

Figure 5.16 – Effect of Gas Price on MPC Results – Stage 1

In these simulations, there are several drivers key of MPC outcomes:

1. SRMC: A lower SRMC means that net pool revenue is higher which drives a lower MPC requirement.
2. Generation: Higher generation increases pool revenue and drives a lower MPC.
3. Number of APC-adjusted periods: A lower number of APC-adjusted periods increases pool revenue which drives a lower MPC. This effect is minor compared to the effect of SRMC and generation.

However, the direction of these drivers varies between regions as summarised in Table 5.8. Queensland, New South Wales and Victoria each have counteracting drivers. While these complicated interacting effects make the sensitivity of MPC outcomes to gas price difficult to interpret, overall, the low gas price does not have a material effect on the MPC.

Table 5.8 – Drivers of MPC Results – Stage 1 Low Gas Price Sensitivity

Region	SRMC	Generation	Number APC-adjusted periods (minor effect)	Net effect on required MPC
Queensland	Lower ↓ Lower MPC	Higher ↓ Lower MPC	Higher ↓ Higher MPC	Lower MPC
New South Wales	Lower ↓ Lower MPC	Lower ↓ Higher MPC	Lower ↓ Lower MPC	Approximately zero
Victoria	Lower ↓ Lower MPC	Higher ↓ Lower MPC	Higher ↓ Higher MPC	Lower MPC
South Australia	Lower ↓ Lower MPC	Higher ↓ Lower MPC	Approximately equal ↓ No effect on MPC	Lower MPC

Although the magnitude of the effect on MPC is relatively small, a decrease in gas price does result in a decrease in MPC required for a new entrant OCGT to operate profitably in Queensland, Victoria and South Australia. In these three regions, the decrease in SRMC and increase in generation both drive the MPC requirement lower. In contrast, in New South Wales, the effects of decreasing SRMC and increasing generation counteract each other so that the MPC requirement is approximately equal to the base case.

5.6 Demand and Energy Growth Sensitivity

There is also considerable uncertainty regarding the future growth in demand and energy projections. Historical energy and peak demand forecasts have regularly over-estimated future growth. Sensitivity analysis has been performed to test the robustness of the MPC calculations to alternative levels of demand and energy growth.

The level of installed capacity required to achieve 0.002% USE in each region is strongly related to the growth in peak demand. Therefore, the high and low growth sensitivities exhibit significant differences in the level of installed capacity. The results of these sensitivities are provided in Figure 5.17.

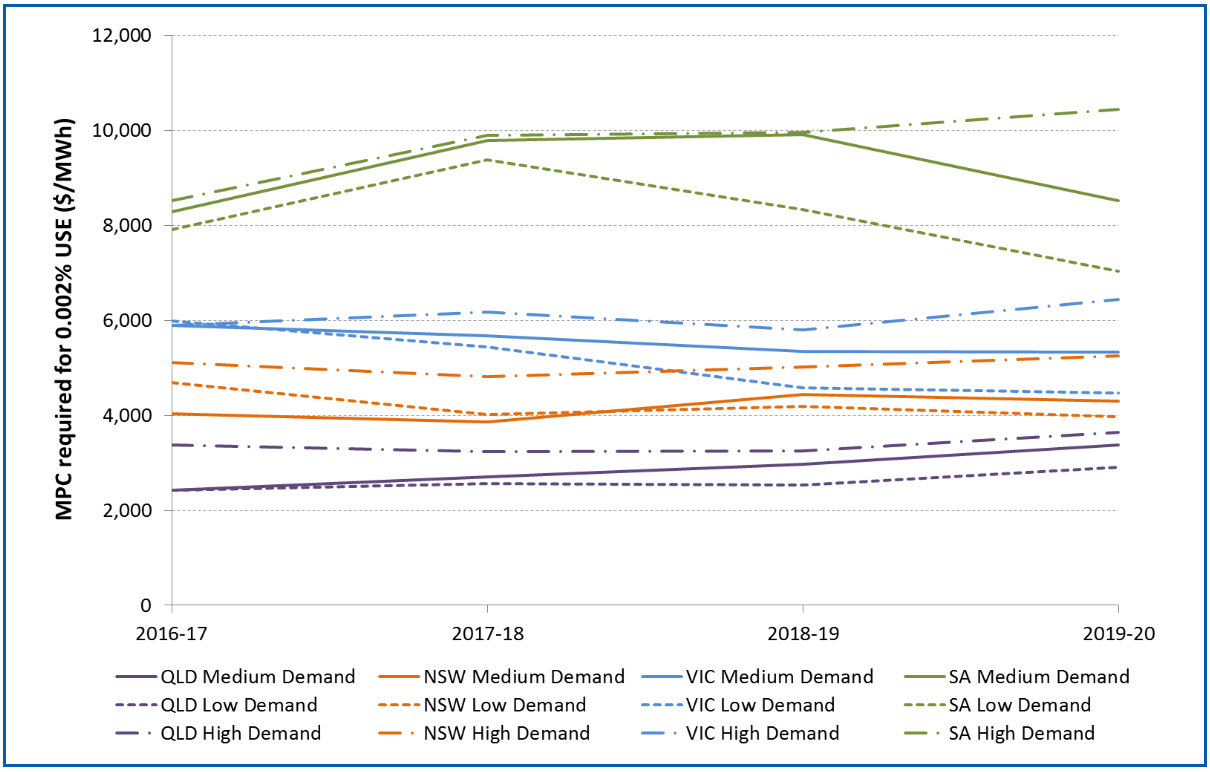

Figure 5.17 – Effect of Demand and Energy Growth Projections on MPC Results – Stage 1

These results indicate that the MPC requirement is proportional to the growth in peak demand and energy. Higher energy and peak demand growth increases the MPC requirement. The impact of the demand and energy growth assumptions increases in magnitude over the study period so that the demand sensitivities are materially different to the Base Case by 2019-20.

In general, the higher the peak demand and annual energy, the higher the MPC required. This is principally driven by the changing proportion of high-priced DSP and hydro bid into the market. In the demand scenarios, DSP and hydro capacity remains fixed while total installed capacity is altered to give an expected USE of 0.002%. As a result, as peak demand and annual energy increases there is proportionally less DSP and hydro capacity. Consequently, there are fewer high priced periods, net pool revenue of the cap defender decreases and the MPC required to achieve the reliability standard increases.

5.7 REDUCED LRET SENSITIVITY

ROAM has performed sensitivity analysis on the level of the LRET. The LRET is an input in ROAM's modelling as sufficient renewable generation is installed to achieve the LRET. The Reduced LRET sensitivity corresponds to an approximate reduction in the LRET from 41 TWh to 27 TWh (see Appendix D). Despite their intermittency, both wind and solar generation do contribute towards meeting peak demand. Therefore, a higher level of thermal capacity is required to meet the reliability standard in this scenario when compared with the Base Case. The results in Figure 5.18 show that the Reduced LRET does not significantly alter the MPC required.

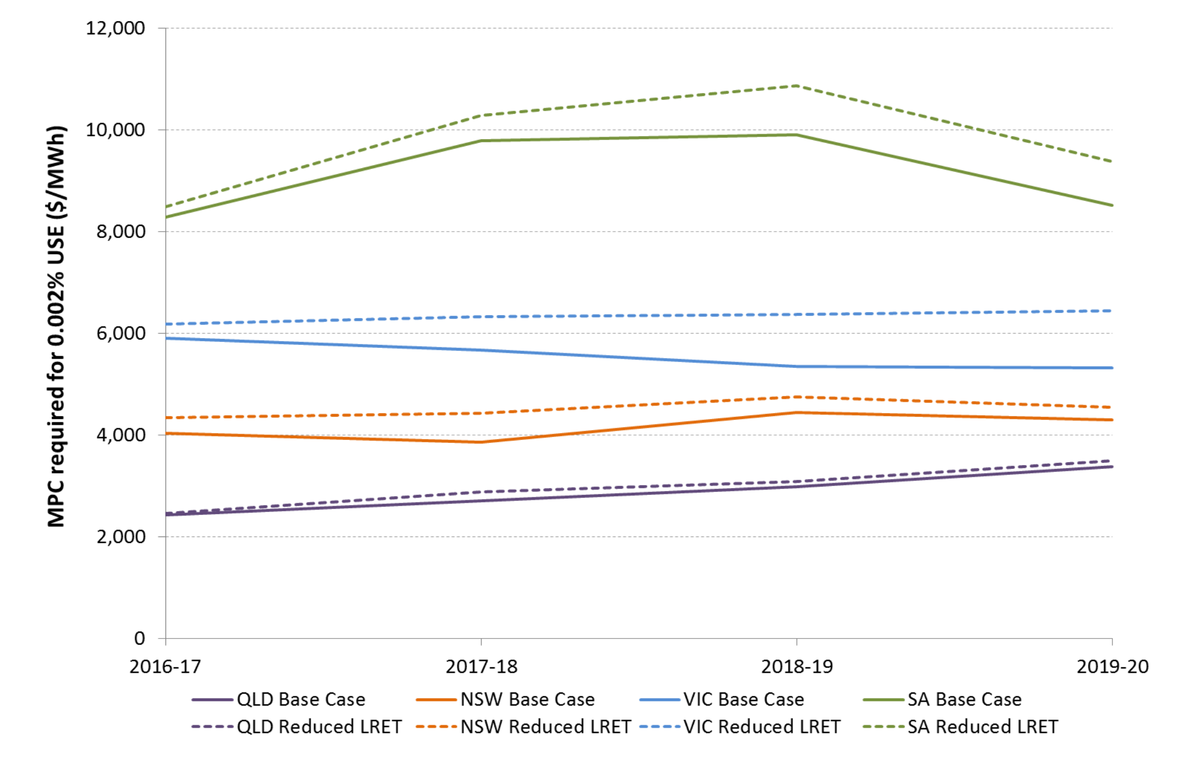

Figure 5.18 – Effect of LRET GWh Target on MPC Results – Stage 1

Although not large in magnitude, the reduced LRET does consistently lead to an increase in the MPC required to achieve the reliability standard. We had initially thought that the reduced LRET would result in a small decrease in the MPC. This reasoning was based on the load factor analysis presented in section 5.1.3. With a reduced penetration of renewable energy, the resulting load factor of net demand increased. However, this increase in load factor did not lead to the expected increase in revenue for the cap defender and therefore, a reduction in the MPC required.

Further analysis has determined that the increase in MPC is a result of the merit order effect. The increasing penetration of renewable generation increases the sensitivity of regional pool price to the average capacity of wind and solar generation, both regionally and in the NEM. ROAM has conducted detailed analysis of the pool price outcomes in 2018-19. These results show that the capacity factor of renewable generation is considerably lower in periods in which pool prices exceeded $300/MWh when compared to average capacity factors. This can be observed in Figure 5.19 which shows the distribution of renewable generation in Victoria for all periods and periods where pool price exceeds $300/MWh.

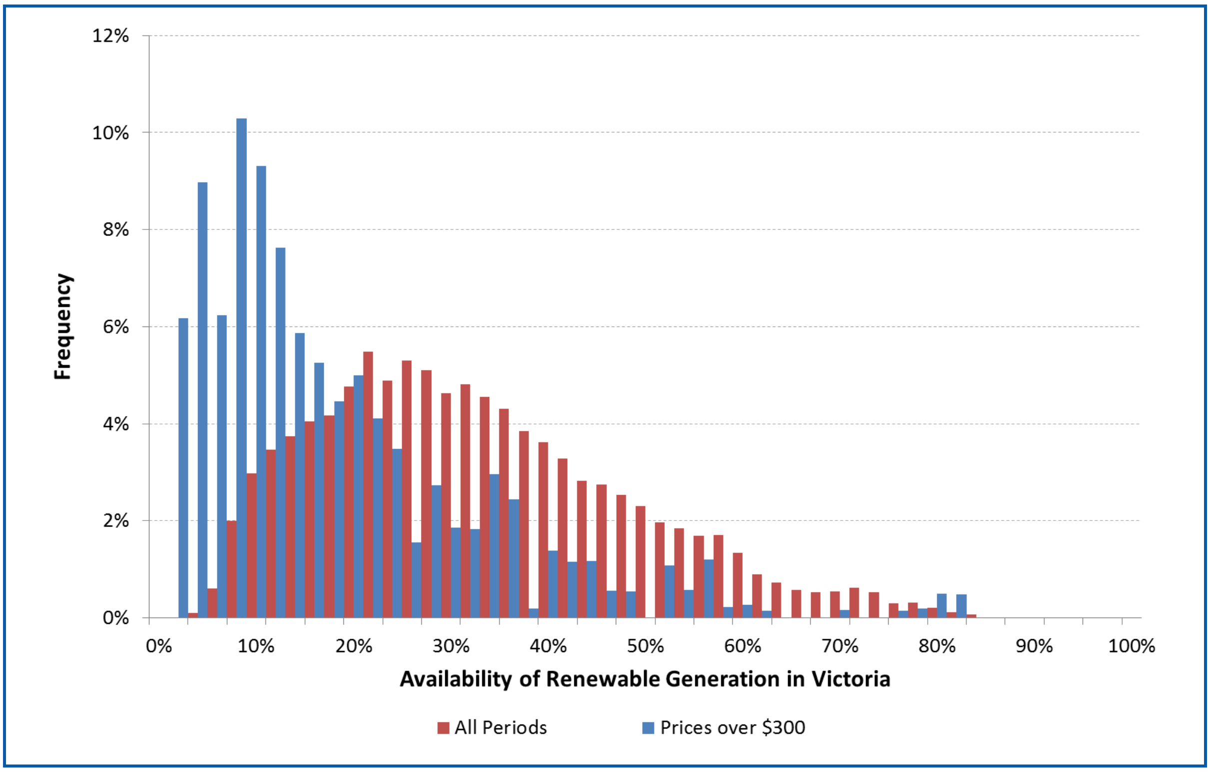

Figure 5.19 – Availability of Renewable Generation in Victoria – Stage 1 Base Case – 2018-19

ROAM has analysed the price differential between the Base Case outcomes and the Reduced LRET sensitivity. The average capacity factor of renewable generation exceeds its contribution to peak demand. Therefore, in the majority of periods, the LRET sensitivity has more capacity (both thermal and renewable) available than the Base Case. Consistent with this finding, the pool prices observed in the LRET sensitivity are lower than those observed in the Base Case in the majority of periods. However, the average reduction in pool price in these periods is low when compared with the average of the less frequent (but larger) increases in pool prices. This disparity is a result of the merit order effect. The large reductions in pool price occur in periods of high price in the Base Case which were correlated with low renewable production. The reduced level of renewable capacity is outweighed in these periods by the increase in available thermal capacity. In Victoria for example, the average capacity factor of wind is only 11% in periods where the pool price reduction in the Reduced LRET sensitivity exceeded $300/MWh.

5.8 DSP Sensitivity

The level of DSP available has a significant influence on the MPC required by the cap defender in a market that is just achieving the reliability standard. DSP capacity is equivalent to a fully available generator from the perspective of USE. However, DSP is only available at high prices (see Table 4.3). The effect of DSP is therefore comparable with that of energy limited generation in that it adds reliability to the market but also provides additional revenue earning potential to the cap defender (in comparison to a thermal generator bidding below $300/MWh). Figure 5.20 shows the impact of a 50% reduction in the capacity of DSP available in each price band.

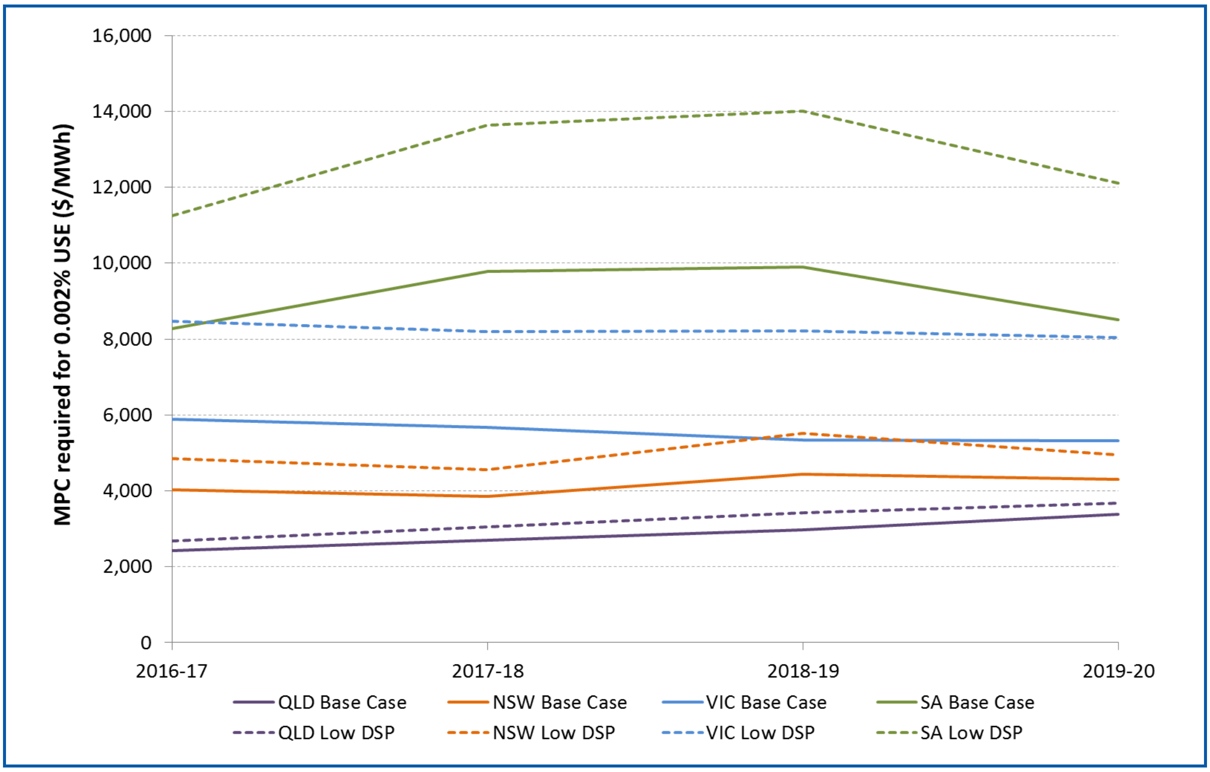

Figure 5.20 – Effect of Reduced DSP Capacity on MPC Results – Stage 1

The largest impact is observed in South Australia and Victoria, the two regions with the highest level of DSP relative to peak demand. Victoria in particular has a significantly higher relative level of DSP than any other region in the NEM. The reduction in DSP results in a material increase in the MPC requirement in each region. The large increase in South Australia results from its own DSP reduction and also the transferred effect of the DSP reduction in Victoria.

ROAM has not quantitatively analysed the impact of an alternative MPC on the quantity of DSP available. 50% of the DSP capacity forecast in the NEFR occurs only at the MPC. This forecast assumes that the reliability settings continue at their current level. Any proposed change to the MPC will need to consider the potential impact on DSP. Qualitative analysis of the relationship between MPC and DSP is provided in Section 9.2.2.

5.9 EXTREME PEAKER OUTCOMES FOR BASE CASE AND SENSITIVITIES

The outcomes of each of the sensitivities detailed above for the extreme peaker approach have not been analysed to the level of detail which has been applied to the cap defender approach.

A number of the sensitivities have no theoretical relationship with the MPC calculation applied in the extreme peaker. These sensitivities relate to input assumptions which are market oriented and that have no impact on the shape of USE. Prior analysis has shown that the extreme peaker methodology is also reasonably robust to changes in demand and energy projections and to the level of renewable generation.

A summary of the outcomes is presented in Figure 5.21. This figure illustrates the range of regional average MPC values calculated by applying the extreme peaker approach to all sensitivities excluding the alternative capital cost estimates. It is evident that the range of sensitivities analysed in this study have only a minimal impact on the extreme peaker outcomes. For consistency with the approach applied in the 2010 Review, the MPC calculation in the extreme peaker methodology is an average of regional MPC requirement.

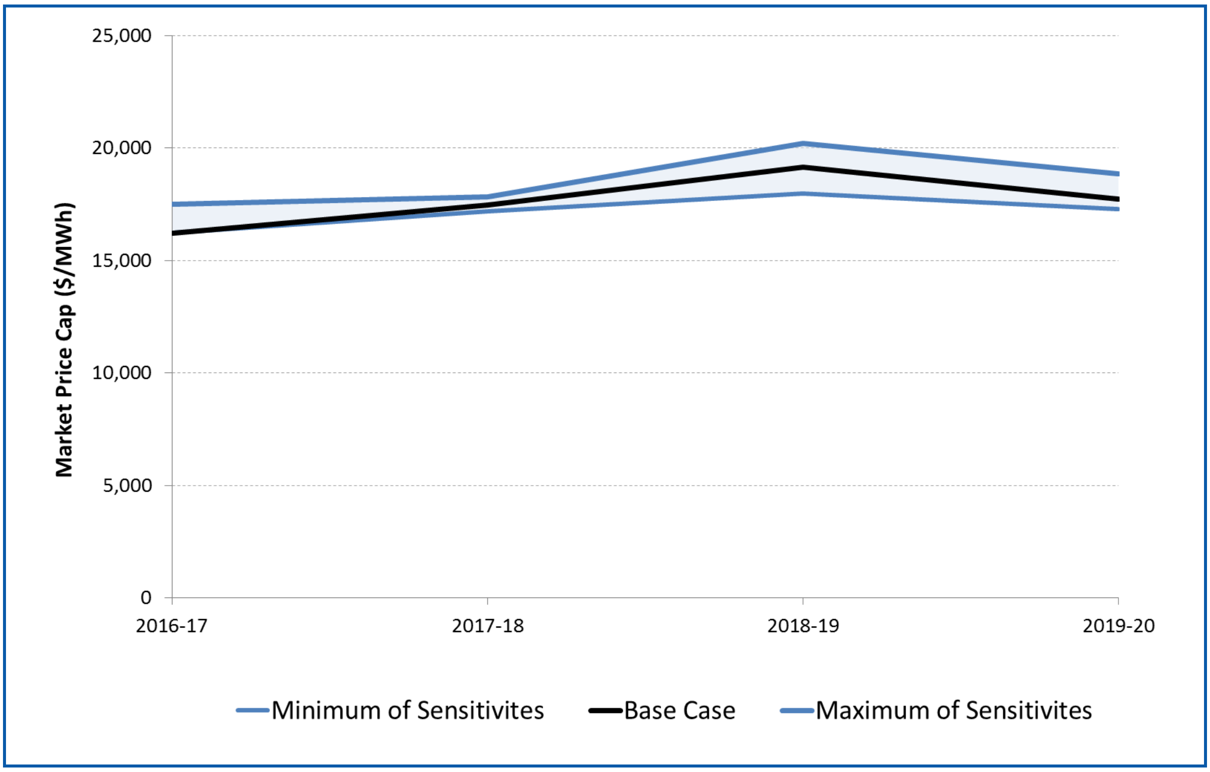

Figure 5.21 – MPC Results for Extreme Peaker – Base Case and Sensitivities (excluding Capex Sensitivities) – Stage 1

Figure 5.22 shows the MPC requirement for the extreme peaker for both an increased and decreased capital cost assumption. Given that the extreme peaker's entire revenue stream is provided by periods where price is at the MPC, there is a direct linear relationship between the capital cost and the MPC required to achieve the reliability standard.

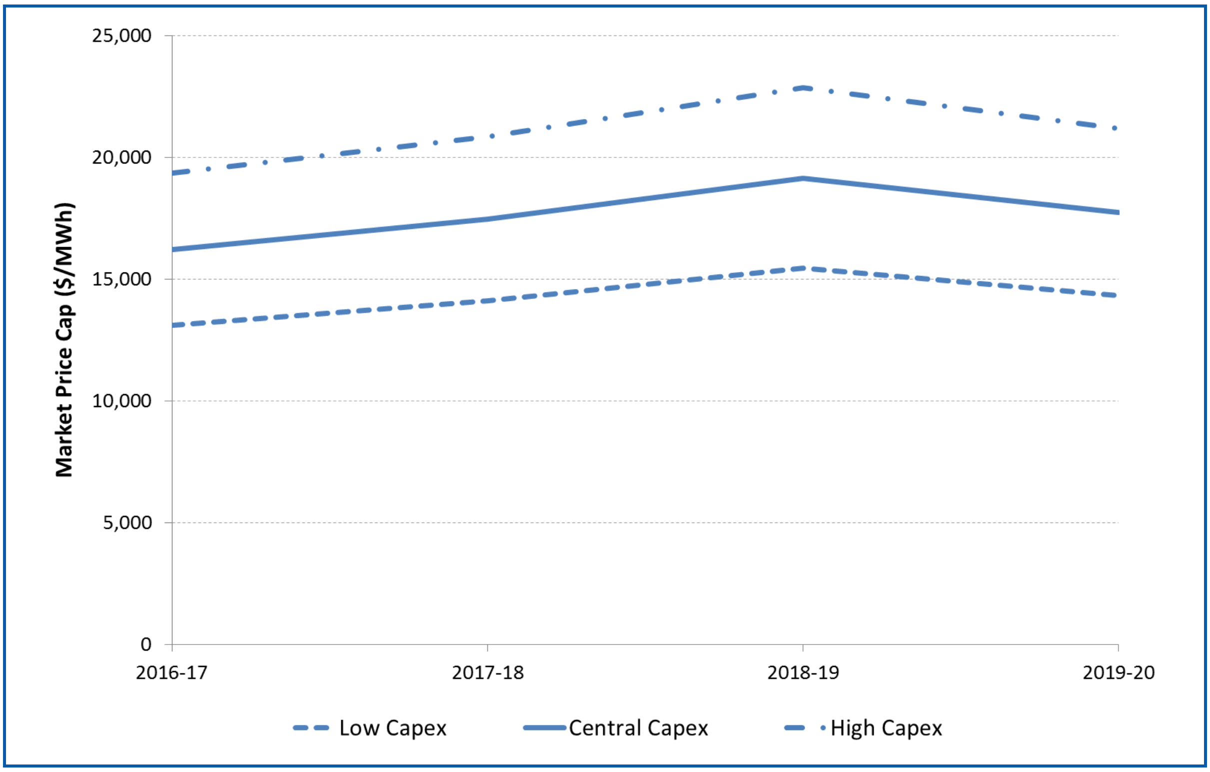

Figure 5.22 – Effect of Capital Cost on MPC Results for Extreme Peaker – Stage 1

6 STAGE 2 RESULTS

6.1 MARKET DEVELOPMENT OUTCOMES

The result of the Base Case Stage 2 modelling is provided in Figure 6.1. In this modelling, renewable generation is installed to meet the LRET while development and retirement of thermal generation is determined by profitability (see Section 3.3.1).

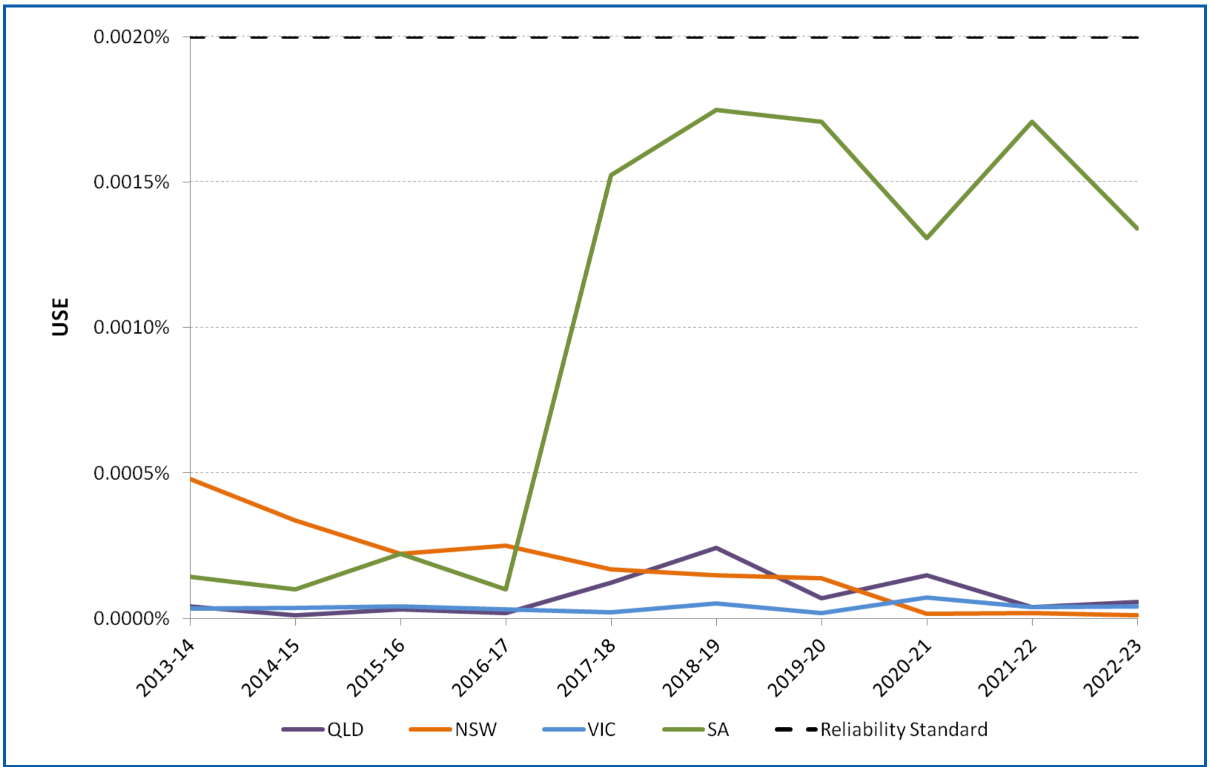

Figure 6.1 – Expected USE with Profitability-Based Thermal Generation Development – Stage 2 Base Case

Expected USE outcomes are highest in South Australia. The combined effect of increasing gas prices and significant renewable capacity erode the profitability of existing gas generation and result in retirements. The remaining regions have very low expected USE in the study period due to low demand and energy growth and because significant low cost generation remains profitable. Therefore, the current oversupply of capacity is maintained. In this modelling, the capital cost of existing generation was treated as a sunk cost so existing plant tend to have low avoidable costs in comparison with new entrant generation.

The jumps in USE outcomes occur due to the lumpy nature of investments and capacity withdrawals. For example, the drop in South Australian USE in 2020-21 is due to a 25 MW OCGT, a 40 MW solar thermal generator and a 130 MW wind farm entering the market simultaneously. The decrease in USE in Queensland in 2019-20 occurs due to a 250 MW CCGT entering the market.

Although some degree of consistency can be expected to be observed between Stage 2 and Stage 1 results, there are a number of factors which restrict alignment of the outcomes of the two approaches. Stage 1 modelling relates to the MPC required to incentivise a new entrant OCGT to operate profitably in a market that achieves the reliability standard. Significant capacity was retired in all regions in order to create this market without reference to its profitability. However, because the capital cost of existing generation is treated as a sunk cost, much of this capacity may have been able to continue to operate profitably at an MPC lower than that required for a new entrant OCGT to operate profitably. Therefore, a region with a surplus in existing capacity may be considerably more reliable in the Stage 2 modelling than Stage 1 outcomes would suggest. Closer alignment between the two modelling approaches occurs in Queensland where new capacity is incentivised to enter the market due to demand and energy growth.

6.2 FIXED PLANTING OUTCOMES

In addition to assessing expected USE with profitability-based thermal generation development and retirement, ROAM also assessed expected USE with fixed thermal planting and renewable planting to meet the LRET. This approach has been applied for the Base Case and a number of supply and demand sensitivities (see Section 3.3.2).

6.2.1 Base Case

Expected USE in the Base Case with fixed thermal planting is shown in Figure 6.2. New South Wales, Victoria and South Australia each experience negligible USE within the study period. Queensland experiences 0.0001% USE in 2018-19 increasing to 0.0004% USE by 2022-23; it does not breach the standard throughout the study period.

These results are consistent with AEMO's assessment of expected USE in the 2013 *Electricity Statement of Opportunities*[23] (ESOO). AEMO's assessment is based on a market including existing and committed generators whereas the market used in the modelling here also includes sufficient new renewable capacity to meet the LRET. This additional capacity means that the expected USE is lower in this assessment than the ESOO. The ESOO predicts that Queensland will breach the reliability standard in 2019-20 if all existing generators keep operating and only currently committed new generators enter the market. The outcomes in Figure 6.2 suggest that with additional renewable generation to meet the LRET, the reliability standard in Queensland will not be breached in the next decade. In 2022-23, the ESOO predicts 0.0005% USE in New South Wales and 0.001% USE in Victoria and South Australia, all within the reliability standard. The modelling here suggests that with additional renewable generation to meet the LRET, there is no USE expected in these regions.

[23] Available at: http://www.aemo.com.au/Electricity/Planning/Electricity-Statement-of-Opportunities. Accessed 7th November 2013.

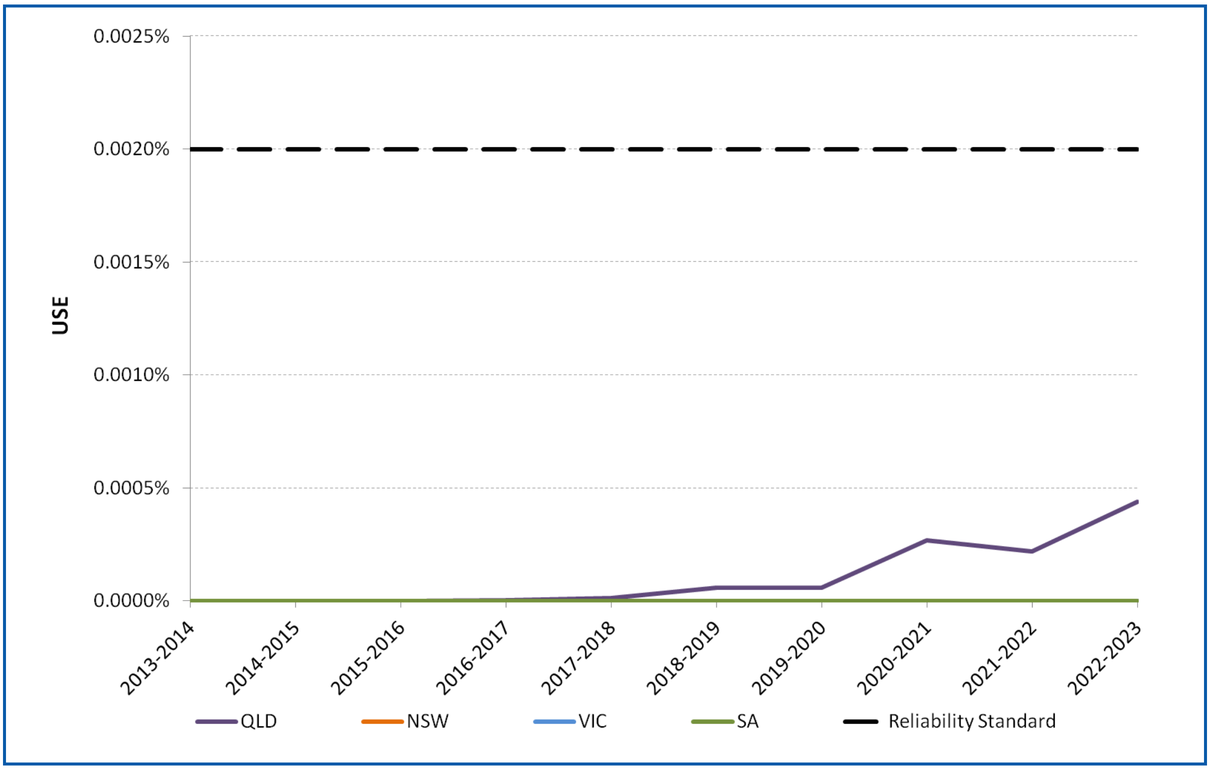

Figure 6.2 – Expected USE with Fixed Thermal Generation – Stage 2 Base Case

6.2.2 Demand and Energy Growth Sensitivity

The expected USE in each region varies in the Low Demand and High Demand sensitivities as shown in Figure 6.3 and Figure 6.4 respectively. Under low demand and energy growth (Figure 6.3), there is no USE expected in any region (note the lines in the chart lie on top of each other along the x-axis). In contrast, under high demand and energy growth (Figure 6.4), USE is expected to be significantly higher in Queensland than under the medium demand and energy growth assumptions. Queensland is expected to breach the reliability standard in 2019-20. As in the Base Case, there is no USE expected in New South Wales, Victoria or South Australia within the study period (note that several lines in the chart lie on top of each other along the x-axis).

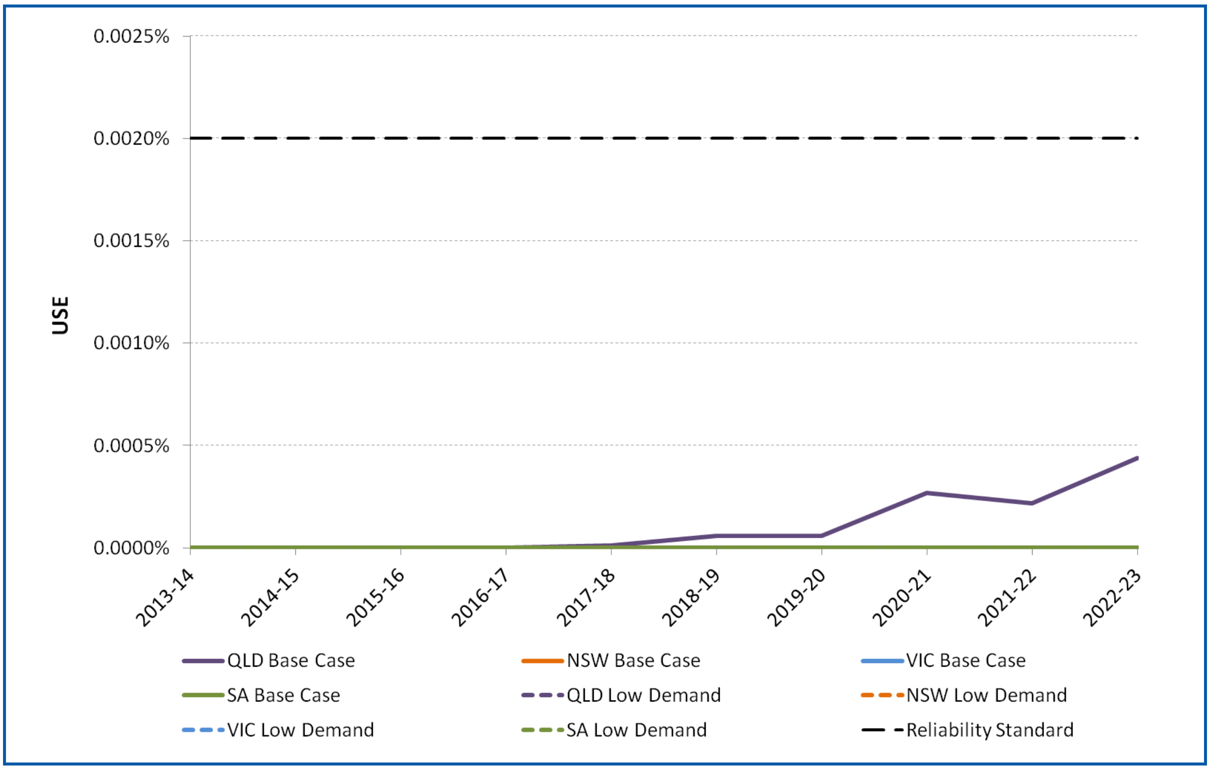

Figure 6.3 – Expected USE with Fixed Thermal Generation – Stage 2 Low Growth

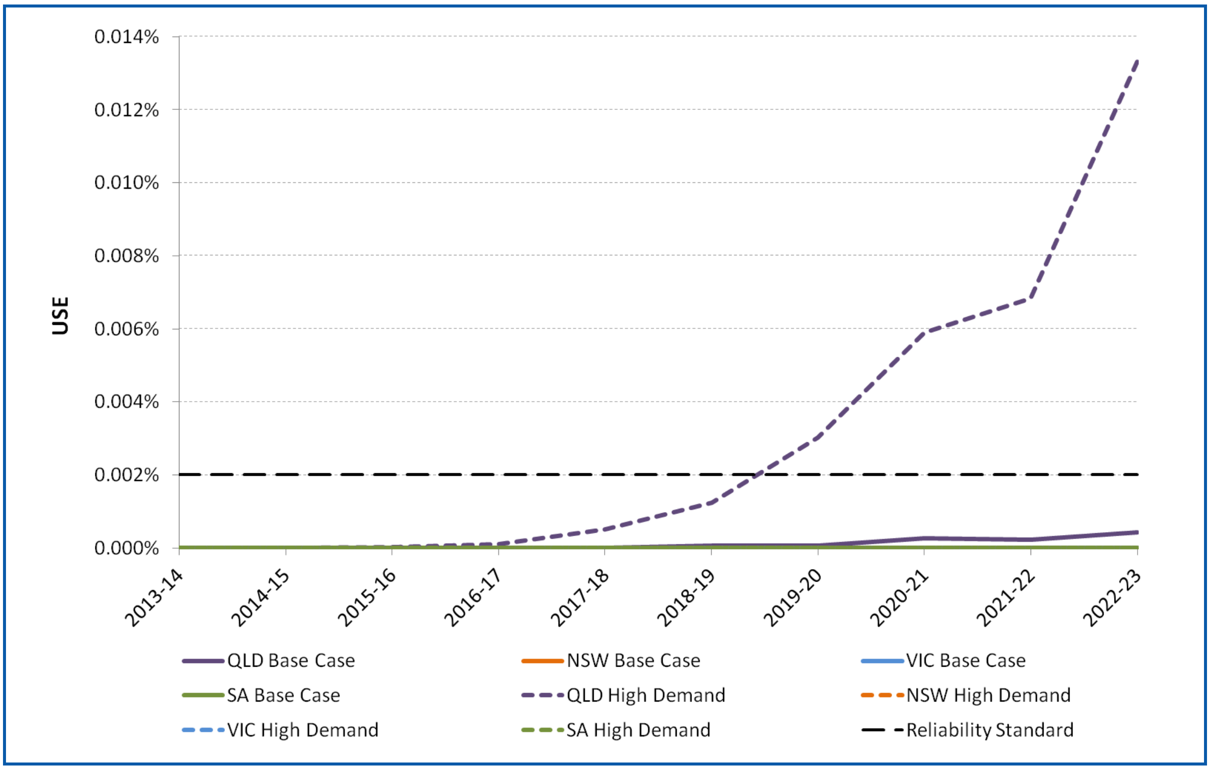

Figure 6.4 – Expected USE with Fixed Thermal Generation – Stage 2 High Growth

6.2.3 Reduced LRET Sensitivity

There is no difference in the USE outcomes observed between the Reduced LRET sensitivity and the Base Case. This is shown in Figure 6.5. In ROAM's assumptions, there is no difference in the amount of renewables installed in Queensland between the two LRET assumptions. Therefore, there is no impact on Queensland USE outcomes. No other region exhibits any material USE. Therefore, the reduction in renewable capacity has no impact on USE outcomes in these regions.

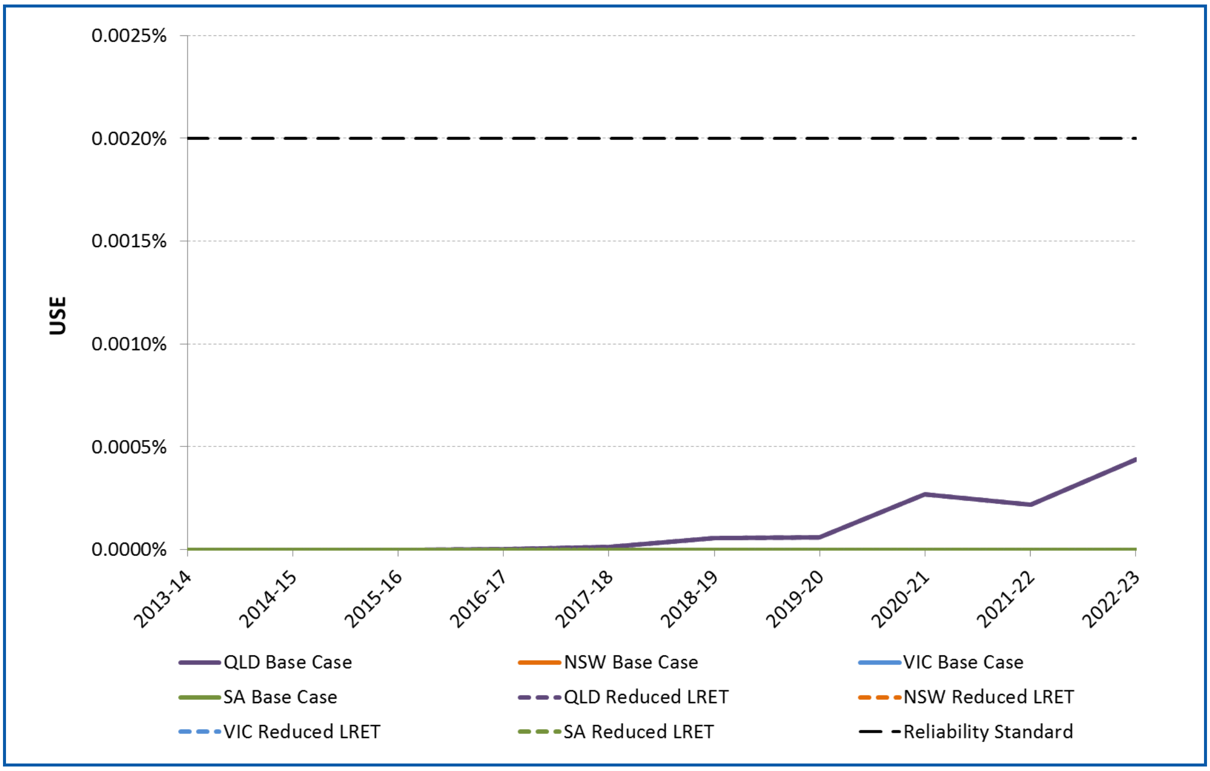

Figure 6.5 – Expected USE with Fixed Thermal Generation – Stage 2 Reduced LRET

6.2.4 DSP Sensitivity

The expected USE in each region varies in the Reduced DSP sensitivity as shown in Figure 6.6. As in the Base Case, there is no USE expected in the study period in New South Wales, Victoria and South Australia (note that the lines on the chart lie on top of each other along the x-axis). There is an increase in expected USE in Queensland, but it remains below the reliability standard.

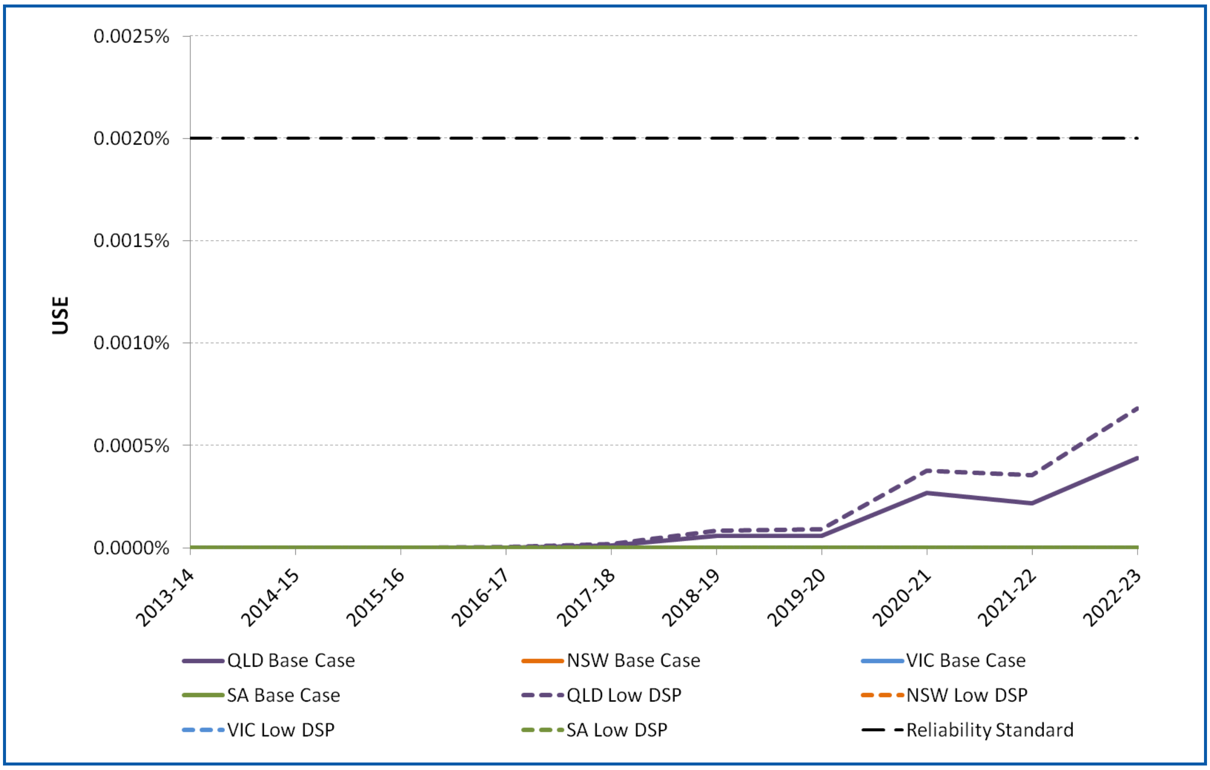

Figure 6.6 – Expected USE with Fixed Thermal Generation – Stage 2 Low DSP Capacity

7 STAGE 3 RESULTS

ROAM has conducted seventeen market simulations with varying levels of new entrant OCGT capacity in each mainland NEM region. The USE outcomes of these studies range from 0.0055% to 0.0004%. Planting is adjusted to ensure that USE outcomes are consistent between the NEM regions.

The total system cost relating to a given level of reliability is calculated from the simulation outcomes. An increased level of reliability in the market results in a lower cost of USE, valued at the VCR. However, this increased reliability requires additional capacity investment and a relatively small increase in variable generation costs. The optimum reliability standard for an assumed value of VCR occurs when the marginal cost of generation investment is equal to the marginal value of reliability. This optimum is therefore at the minimum of the total cost curve.

An example total cost curve is provided in Figure 7.1. This figure shows the relationship between system cost and USE in 2016-17 for an assumed VCR of $30,000/MWh. This result shows that the optimum level of reliability is approximately 0.002%, given the assumed VCR. The total system cost incorporates all variable generation costs, fixed operating and maintenance costs and the annualised capital cost of any investments made after 1 July 2013. The absolute value of generation cost is not critical to this analysis. Only the relativity between the cost of generation in the range of planting scenarios is relevant to this assessment. For comparison, the total cost curve is also provided for a VCR of $55,000/MWh in Figure 7.2. It is evident that a higher cost of USE increases the level of reliability which is optimal from an economic perspective.

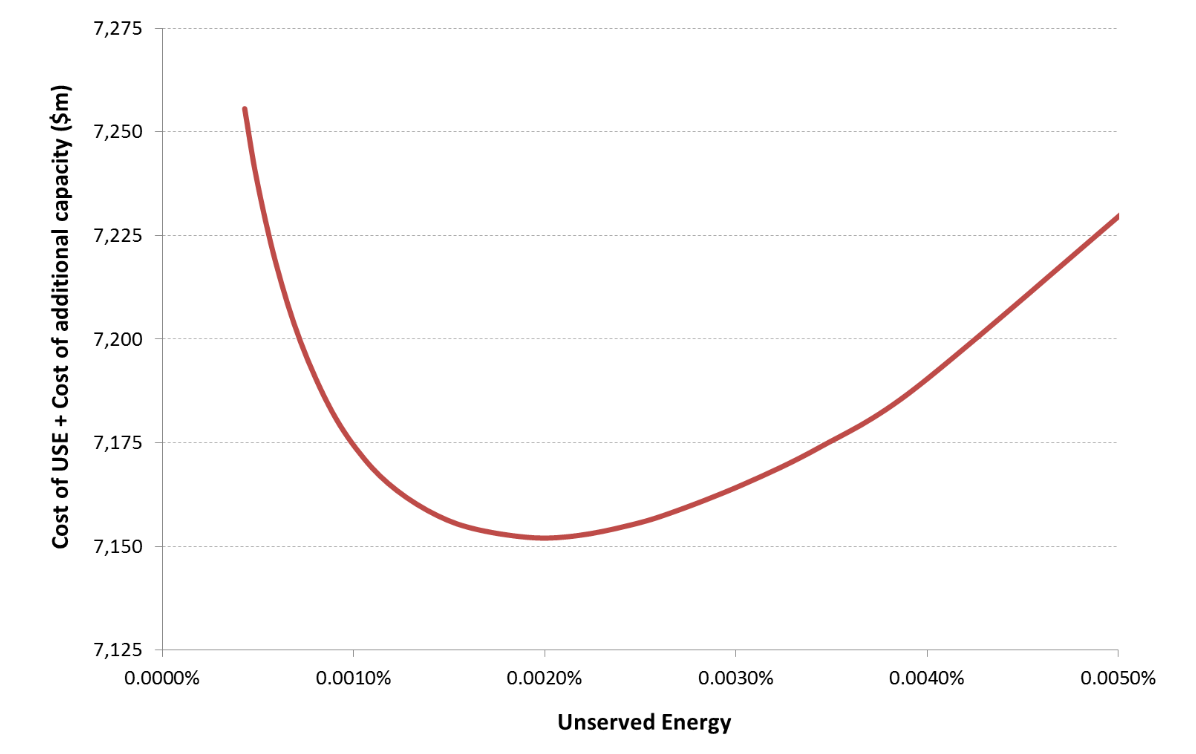

Figure 7.1 – Stage 3 Results – 2016-17 USE vs Cost of USE and Generation – VCR = $30,000/MWh

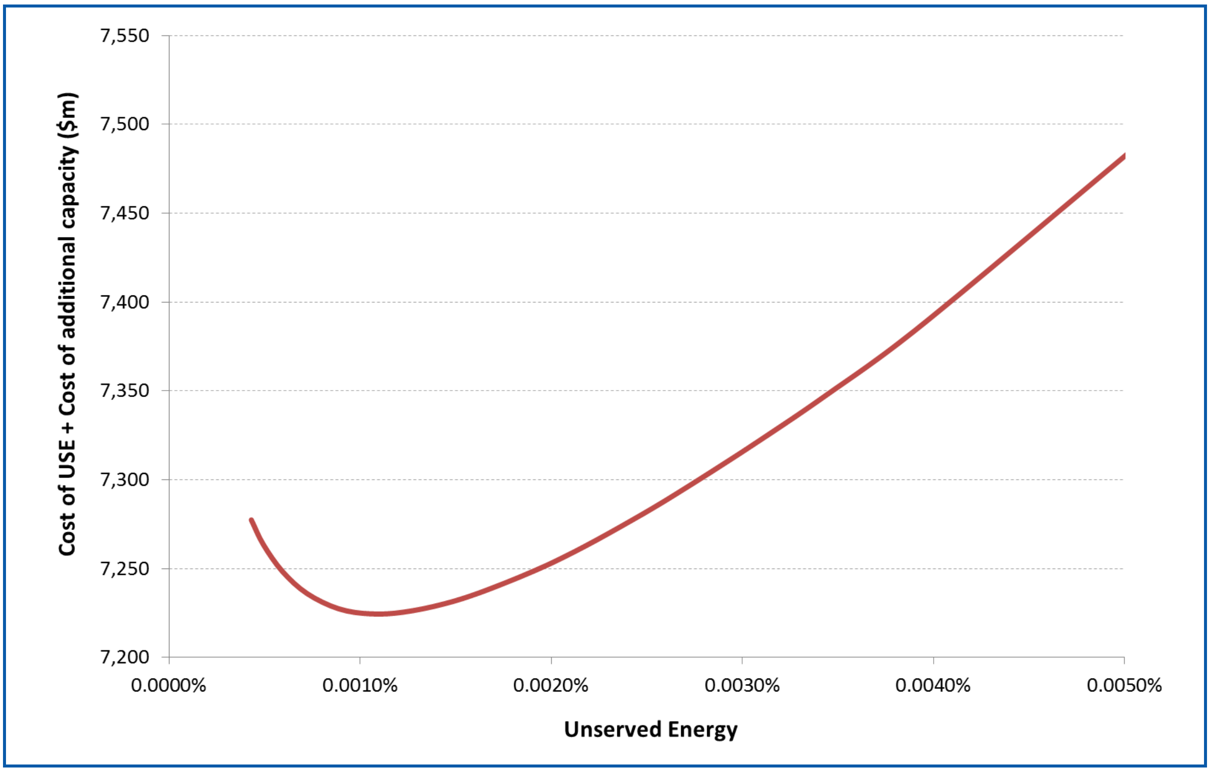

Figure 7.2 – Stage 3 Results – 2016-17 USE vs Cost of USE and Generation – VCR = $55,000/MWh

Given that there is significant uncertainty regarding the true value of VCR, ROAM has calculated the relationship between the assumed VCR and the optimum reliability standard. These outcomes are provided in Figure 7.3. It is evident that this relationship is relatively constant over the modelling period.

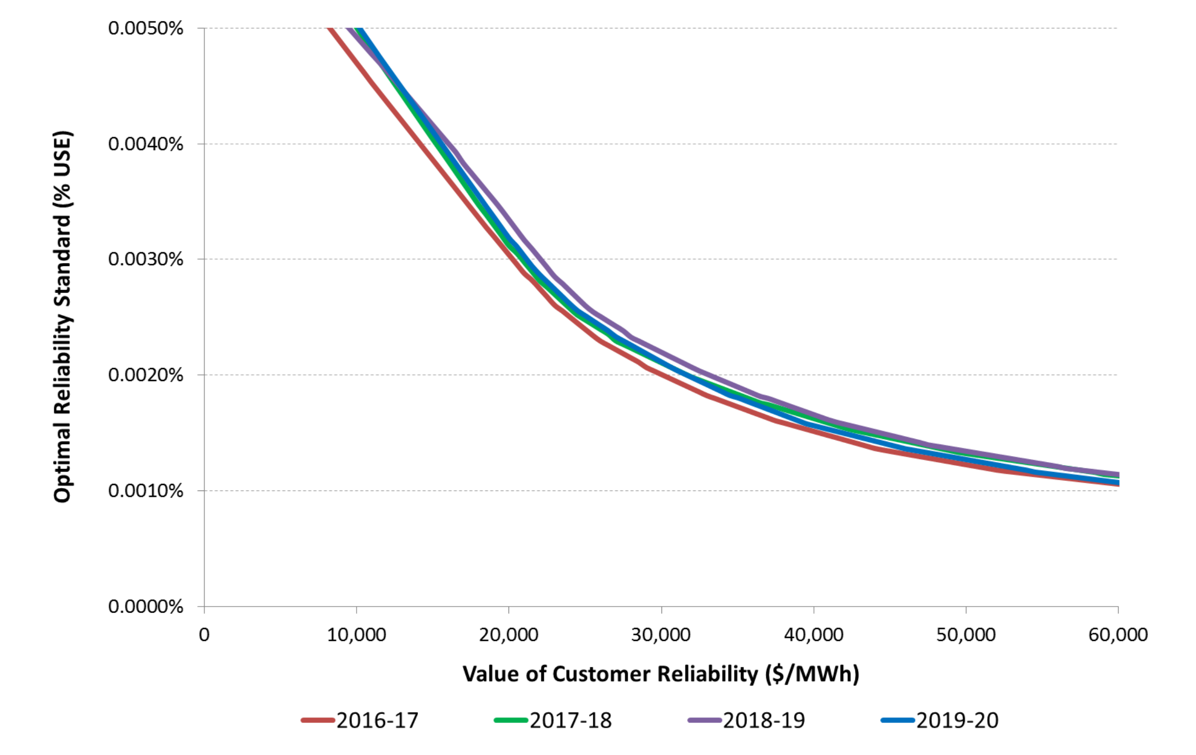

Figure 7.3 – Stage 3 Results – VCR vs Reliability Standard

8 Stage 4 Results

This section presents the results of the WAUC modelling which was conducted to inform a review into the suitability of the current MFP. ROAM has also commented qualitatively on the suitability of the setting given this economic analysis and consideration of the financial risks for market participants. ROAM has also provided a historical analysis of the effect of the MFP in the operation of the market in the recent past.

8.1 Modelling Outcomes

The WAUC modelling features cycling in each of the four study years. This indicates that supply relative to demand net of zero-bidding renewables is high enough that it is economically efficient for some units to cycle. That is, large supply relative to demand net of renewables results in an economic driver for units to incur cycling costs rather than continuing to operate in all periods.

ROAM has completed WAUC modelling using warm start cycling cost assumptions. The minimum (i.e. the largest negative value) MFP in each year for all generators that cycle, calculated using equation (1), is summarised in Table 8.1.

Table 8.1 – Maximum MFP Required for Economically Efficient Cycling

	2016-17	2017-18	2018-19	2019-20
Maximum MFP ($/MWh)	-2	-19	-29	-11
Unit setting maximum MFP	YABULU	PPCCGT	PPCCGT	NPS1
SRMC ($/MWh)	34.48	52.78	53.26	22.88
Total Cycling Cost ($)	16,320	48,756	48,756	86,920
Minimum Load (MW)	82	170	170	160
Shortest Cycling Period (hours)	5.5	4	3.5	16

CCGTs have the lowest cycling costs and are consequently cycled up to 300 times in all study years. Units with the largest cycling costs are large, coal-fired generators. There is sufficient residual demand after zero-bidding renewables are dispatched such that these units rarely need to cycle. Eraring, Liddell and Vales Point do cycle, particularly toward the end of the study period. However, when these units do cycle, there is not economic driver for these units to cycle off for a short duration of time. Therefore, these units remain offline for between two days and over one week such that the cycling cost per MWh is low.

Given uncertainty regarding the true cycling costs of units, ROAM has performed sensitivity analysis on these assumptions. ROAM performed a warm start WAUC simulation which doubled the original assumed cycling costs. The results of this study are provided in Table 8.2. As with the original study, no short-term coal cycling is economically efficient. The market floor price requirement is slightly lower than the values produced using the base case cycling assumptions.

Table 8.2 – Maximum MFP Required for Economically Efficient Cycling – Double Cycling Cost

	2016-17	2017-18	2018-19	2019-20
Maximum MFP ($/MWh)	-27	-52	-35	-41
Unit setting maximum MFP	YABULU	PPCCGT	PPCCGT	PPCCGT
SRMC ($/MWh)	34.48	52.78	53.26	54.51
Total Cycling Cost ($)	32,640	97,512	97,512	97,512
Minimum Load (MW)	82	170	170	170
Shortest Cycling Period (hours)	6.5	5.5	6.5	6

ROAM also completed modelling incorporating hot start cost assumptions for coal generation. With these lower cost assumptions, there was still no economic driver for coal generation to cycle for short periods of time. Without the need for short-term, high cost cycling, there is little evidence that a large negative MFP is required to incentivise economically efficient cycling behaviour in the near future from a cost point of view. The following section provides an assessment of the requirement for the market floor price if short-term coal cycling did occur.

8.2 Cost of Cycling For One Hour

ROAM has calculated the market floor price requirement provided that coal units are required to cycle off for one hour given a lack of available demand net of renewables. This assessment is based on the hot start cycling costs provided in Section 4.7. The market floor price requirement for a unit (using the assumption that the duration of cycling is one hour) is dependent on the SRMC of the unit, the hot start cycling cost and the minimum load.

Table 8.3 shows the range of market floor price required within each cycling class for one hour cycling to be beneficial. However, ROAM has found no evidence that this behaviour is required in the near future.

Table 8.3 – Market Floor Price Requirement for 1 Hour Cycling

Cycling Class	Minimum MFP	Maximum MFP
Small sub-critical coal	-594	-299
Large sub-critical coal	-758	-342
Supercritical coal	-674	-444
CCGT	-240	-81

8.3 Impact of the Market Floor Price in History

The analysis in Sections 8.1 and 8.2 focuses on the floor price required to incentivise economically efficient cycling outcomes. A further consideration for the MFP is the impact of the setting being significantly below this value. ROAM has examined historical occurrences of dispatch interval pricing at or near the MFP to inform this investigation.

8.3.1 Frequency of Prices at the Market Floor Price

The MFP has occurred infrequently in recent history. The MFP is most frequently observed in Queensland with 25 dispatch intervals occurring since 1 July 2011. The MFP has occurred for 15 dispatch intervals in South Australia. MFP events have been very rare in New South Wales and Victoria.

8.3.2 Drivers for Market Floor Price Events

The frequency of floor price events detailed above is observed to be consistent with the frequency of high pool prices observed in the mainland NEM regions; Queensland and South Australia observe the most frequent floor price events and prices over

$5,000/MWh. This is partly driven by the behaviour of market participants in the dispatch intervals which follow a pool price spike. For example, the pool price outcomes in the trading interval ending 13:30 on 30 August 2012 is provided in Table 8.4. This period shows that the floor price was invoked due to "race to the floor" bidding of generation in Queensland in an attempt to maximise dispatch in a high price trading interval.

Table 8.4 – Queensland Pool Price Outcomes – 30 August 2012

Dispatch Interval Ending	Queensland Pool Price ($/MWh)
13:05	7249.93
13:10	-471.09
13:15	-1000
13:20	-1000
13:25	-1000
13:30	-1000

The MFP is also found to occur in periods of low demand. However, demand is not sufficiently low in these periods that the must-run capacity of units that are operating cannot be dispatched. These events are short in duration and prices return to cost-reflective levels as generation portfolios adjust.

Neither of these drivers for market floor price outcomes provides strong evidence that the current MFP is required to achieve an efficient operation of the NEM. However, these events may impose additional risks for market participants and can negatively impact productive efficiency.

8.3.3 Market Floor Price Bidding

Generators in the NEM regularly bid a proportion of their capacity at the MFP. This is particularly true of baseload generation which often bids at least its must-run capacity at the market floor. Market floor bidding is also implemented as a strategy to maximise dispatch. This behaviour may be the result of a prior price spike (see 8.3.2). MFP bidding may also be used to avoid curtailment resulting from a transmission constraint equation. This behaviour has been well documented in the AEMC's Transmission Frameworks Review.[24] This race to the floor bidding can result in inefficient outcomes and potentially exacerbate negative settlements residues. The effectiveness of this behaviour could be reduced by increasing the MFP.

[24] See http://www.aemc.gov.au/market-reviews/completed/transmission-frameworks-review.html

9 STAGE 5 RESULTS

This section analyses and discusses the potential non-reliability impacts of changing the MPC on the market. All quantitative analysis compares an alternative MPC of $9,000/MWh to the current MPC of $13,100/MWh. The value of the alternative MPC was chosen in consultation with the Reliability Panel but does not represent a recommendation. In addition to analysis of historical data, dispatch modelling of the following two markets under the current and alternative MPC has been examined for the period 2016-17 to 2019-20:

- A market with expected USE of 0.002% (Stage 1, Base Case)
- A minimal retirement market in which renewables are installed to meet the LRET, half of Hazelwood (800 MW, 4 units) and all of Wallerawang (1,000 MW, 2 units) are retired before 2016-17, Mackay GT retires in March 2017 and a 250 MW CCGT is installed in South West Queensland in 2019-20.

The second market is intended as a more realistic possible future state of the NEM than the first since the current supply-demand balance is such that expected USE is well below 0.002% in all regions except Queensland.

9.1 *MARKET PRICING IMPACTS*

9.1.1 Volatility of New Entrant Returns

Revenue outcomes for the cap defender were quite different in the two markets analysed.

- In the minimal retirement market, the cap defender is not profitable in any region for either MPC value analysed;
- In the 0.002% expected USE market the cap defender is profitable on average in all regions with an MPC of $13,100/MWh. With an MPC of $9,000/MWh, the cap defender is profitable in Queensland, New South Wales and Victoria in all years and in South Australian in 2016-17. It has an expected net loss of between $480/MW/year and $7,560/MW/year in South Australia in 2017-18 to 2019-20.

The discussion in this section focuses on the volatility of revenue as MPC changes. Overall, at the lower MPC, both the expected net revenue and the variability in net revenue decreases for the cap defender, as illustrated in Figure 9.1 for the market with 0.002% expected USE. The reduction in MPC leads to lower pool price outcomes and therefore a reduction in the value of cap contracts sold by the OCGT. The variability of returns in each of the iterations falls as a reduction in MPC reduces pool price volatility. The risk for a contracted generator is that they are not operating in periods of high price. Reducing the MPC leads to some mitigation of this risk for contracted generation.

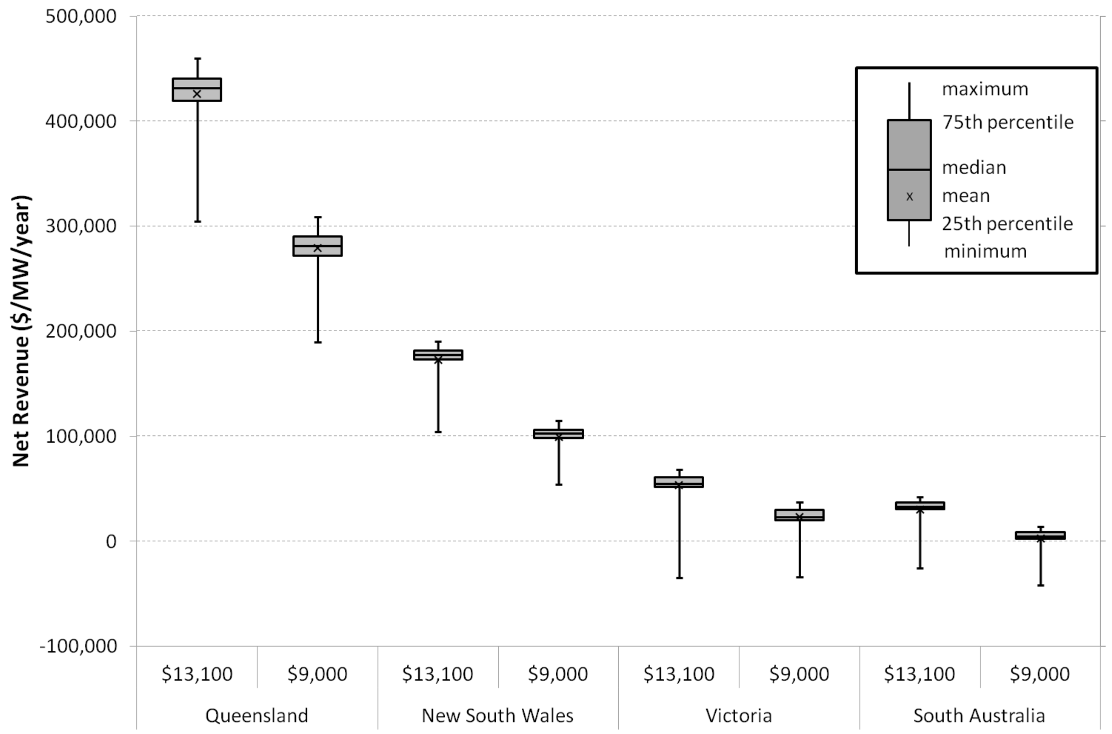

Figure 9.1 – Distribution of Net Revenue (Weighted Average of POEs) Across 25 Iterations, 5 Reference Years – Market with 0.002% Expected USE – 2016-17

Figure 9.2 shows the relationship between the standard deviation and mean of the net revenue of the cap defender for different values of the MPC in a market with 0.002% expected USE. The cap defender is assumed to be 100% contracted in this figure. As MPC increases, the average return for the cap defender in each region increases. With the exception of a slight deviation at the lowest end of the curves in New South Wales and South Australia[25], an increased MPC results in an increase in both expected return and the volatility of that return. The decreasing gradient of these curves indicates that as MPC increases, the level of risk increases at a faster rate than expected return.

[25] The lowest value in these figures corresponds to an MPC of $300/MWh. In this instance, a $300 cap contract has no value. Therefore, the cap defender effectively has no hedging and is fully exposed to the frequency of periods of price at $300/MWh. When the MPC increases slightly, the contract obtains some value. This increases returns and briefly leads to a reduction in risk for the cap defender.

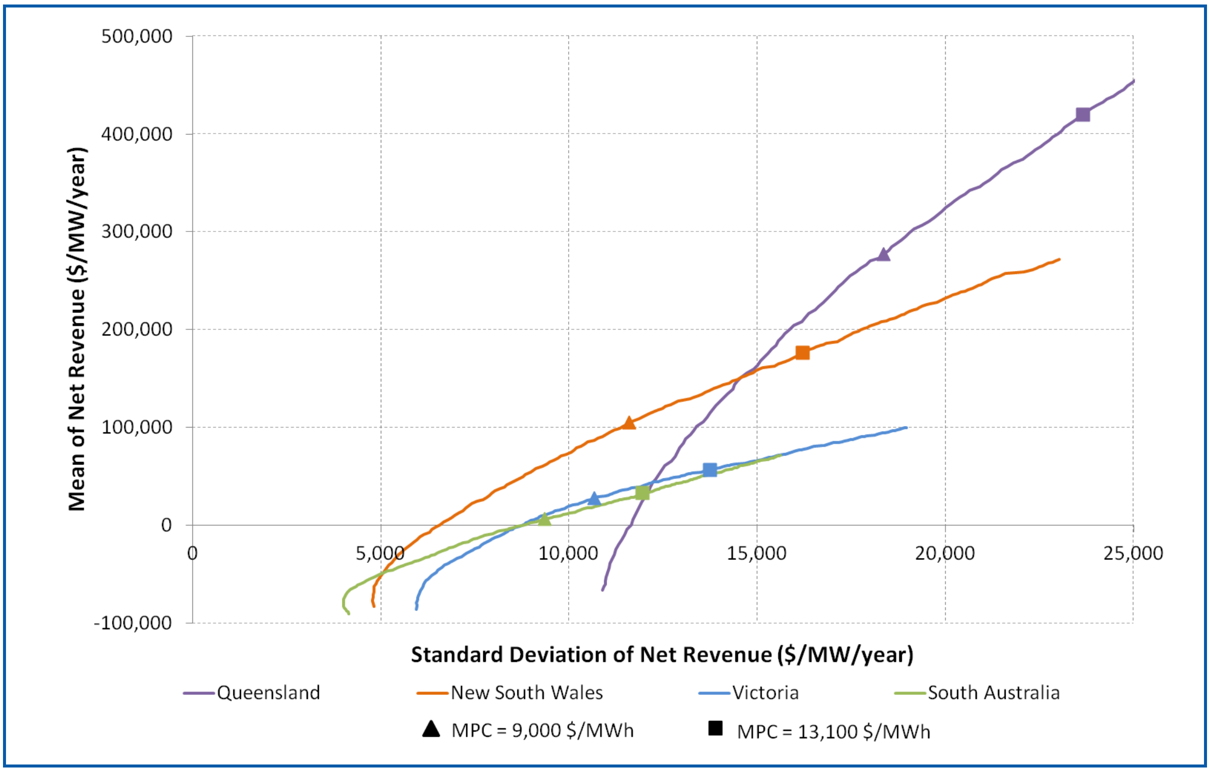

Figure 9.2 – 100% Contracted Cap Defender Risk vs Return – Market with 0.002% Expected USE – 2016-17

Although a higher MPC generally results in higher expected net revenue, there are instances where increasing the MPC decreases revenue in individual iterations for a contracted cap defender. This occurs in iterations where MPC events are infrequent and where the cap defender's outages happen to coincide with these events. In these iterations, missing the few high-price events has a large impact on revenue and increasing the MPC can cause the overall revenue to decrease.

In the minimal retirement market, this occurs in between 0.4% and 4.8% of iterations, depending on region. In the market with 0.002% expected USE, there are many more USE events so revenues are higher than in the minimal retirement market and missing a few high-priced periods due to outages does not have a large impact on revenue. As a result, increasing the MPC decreases revenue in less than 0.2% of iterations. The impact of the MPC in a market which is not experiencing significant USE is discussed in Section 9.1.4.

9.1.2 Volatility and Contracting

Expected net revenue is independent of the amount of energy contracted by the cap defender since the value of the contract in this modelling is set such that it equals the expected contract settlement (see Section 3.2.1). However, the volatility of returns is heavily dependent on the level of contracting as shown in Figure 9.3. As contracting level decreases, risk increases because the cap defender is more exposed to both positive and negative deviations in market outcomes from expectations. The rate at which risk increases given a reduction in contracting is proportional to the MPC.

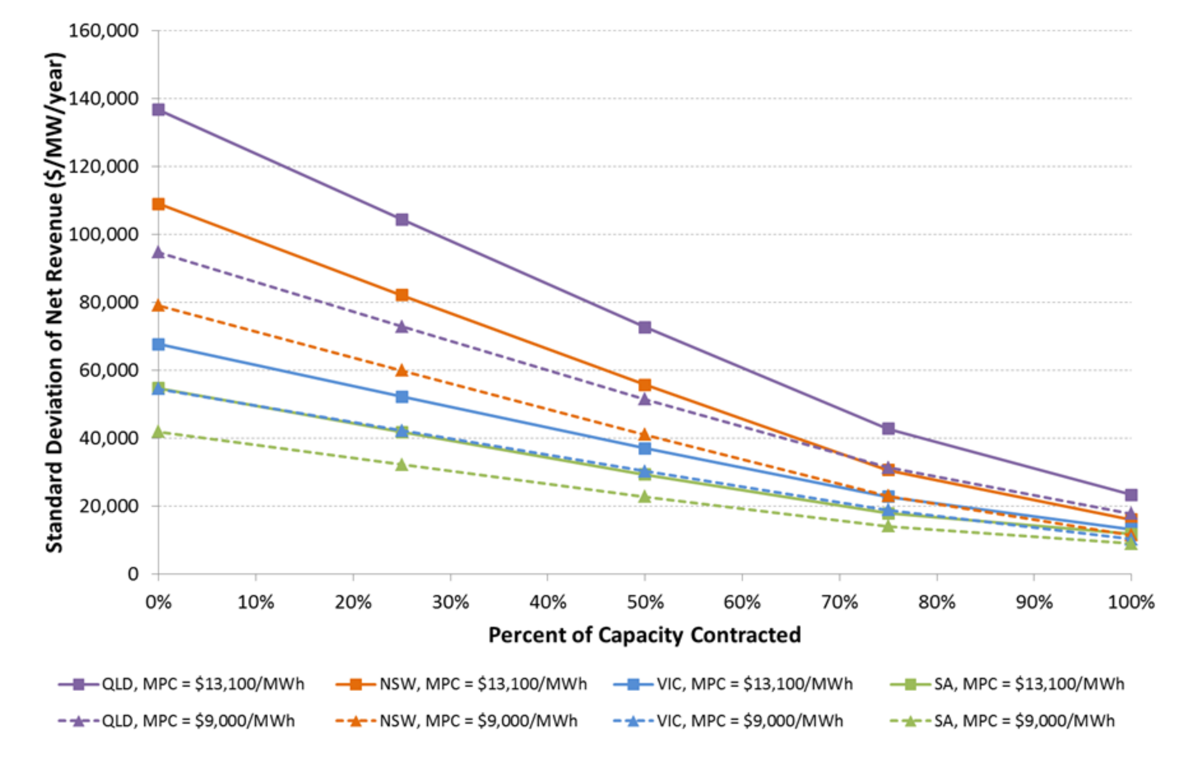

Figure 9.3 – Relationship Between Risk and Contracting Level – Market with 0.002% Expected USE – 2016-17

9.1.3 Impact of the MPC on Contract Markets

The level of the MPC affects future expectations of pool price outcomes. Therefore, an increase in the MPC, which is likely to increase expectations of future pool price outcomes, will lead to an increase in contract prices. A change in MPC will also influence the level of price volatility in the market. This may affect the decisions made by market participants given their level of risk aversion and therefore contract market liquidity.

Historically, retailers and other market customers have been risk averse, enabling cap defenders to charge a premium on contracts. The current value of contract premiums or discounts has not been evaluated as part of this review, and so the analysis has only considered cap defender revenue under fair-valued contracts. A contract premium above fair value would reduce the MPC required to achieve the reliability standard while a discount would increase the MPC required.

Regardless of the current premium on contracts, it is possible that a lower MPC would reduce the incentive for market customers to purchase cap contracts which would in turn reduce contract premiums. Since significant contract discounts would presumably attract speculators there should be a natural lower limit on contract values. However, any contract discount could have impacts on reliability and consequently forms a risk of lowering the MPC.

9.1.4 Historical Analysis of Price Volatility

An understanding of the impact of the MPC in historical outcomes is vital in understanding the potential impacts of an alternative MPC. ROAM has focused this analysis on the period from 1 July 2011 to 25 October 2013. This analysis can only be performed by post-processing historical price outcomes. If a lower MPC was in place, this could result in changes to contracting positions, bidding strategies, the quantity of DSP and other factors that influence pricing outcomes. These impacts have not been incorporated in this analysis. Conclusions should be considered in that light.

The trading interval pool price has not reached the MPC during this period. Furthermore, this period has experienced a significant oversupply of capacity. Therefore, these observations provide an informative illustration of the potential non-reliability market impacts of the MPC.

Although the trading interval price has not reached the MPC, the pool prices in individual dispatch intervals have reached this level. Both Queensland and South Australia have experienced a moderate level of dispatch interval pool price volatility. Price volatility has been less frequent in Victoria and very rare in New South Wales.

In ROAM's forecast modelling, periods of pool prices near or at the MPC generally coincide with high demand, multiple generation outages or the exercise of transient market power. However, historical dispatch interval pool price volatility often results from a range of factors which are not considered in ROAM's modelling. Dispatch interval price spikes are often observed to occur in periods where supply-demand balance is not tight. Rather, short term changes in variables such as demand, intermittent generation, and constraint equation values can cause a "shock" to the regional system. The presence of ramp rates, fast start inflexibility profiles and ancillary service markets restrict the ability of the market to respond to these shocks. A transient price spike occurs which often lasts for only a single dispatch interval. Furthermore, these dispatch interval price spikes are usually difficult to forecasts given that they rely on short-term fluctuations in market variables.

The MPC in the context of this review is considered a driver for new entrant generation, particularly open cycle gas turbine generation. However, transient pool price volatility at the MPC may not provide additional revenue to new entrant thermal generation. This volatility may in fact be a cost to a contracted OCGT. ROAM has considered the historical data in this context. If an OCGT is not already running when a dispatch interval price spike occurs then the generator is unlikely to be operational by the end of the relevant trading interval. ROAM has therefore examined the pool price in the dispatch interval preceding prices in excess of \$5,000/MWh. This provides an indication as to whether an OCGT is likely to be running. This analysis also provides an indication of the duration of these dispatch interval price spike events.

Figure 9.4 illustrates the distribution of dispatch interval prices which preceded price spikes in Queensland. It is evident that only a small proportion of these price spikes immediately followed a price of a similar magnitude. This indicates that these events were usually very short in duration. This figure also shows that a large proportion of these price spikes were preceded by prices below $100/MWh. There is therefore a strong possibility that these price spikes would not be fully captured by an OCGT. A similar outcome is observed in South Australia (provided in Figure 9.5).

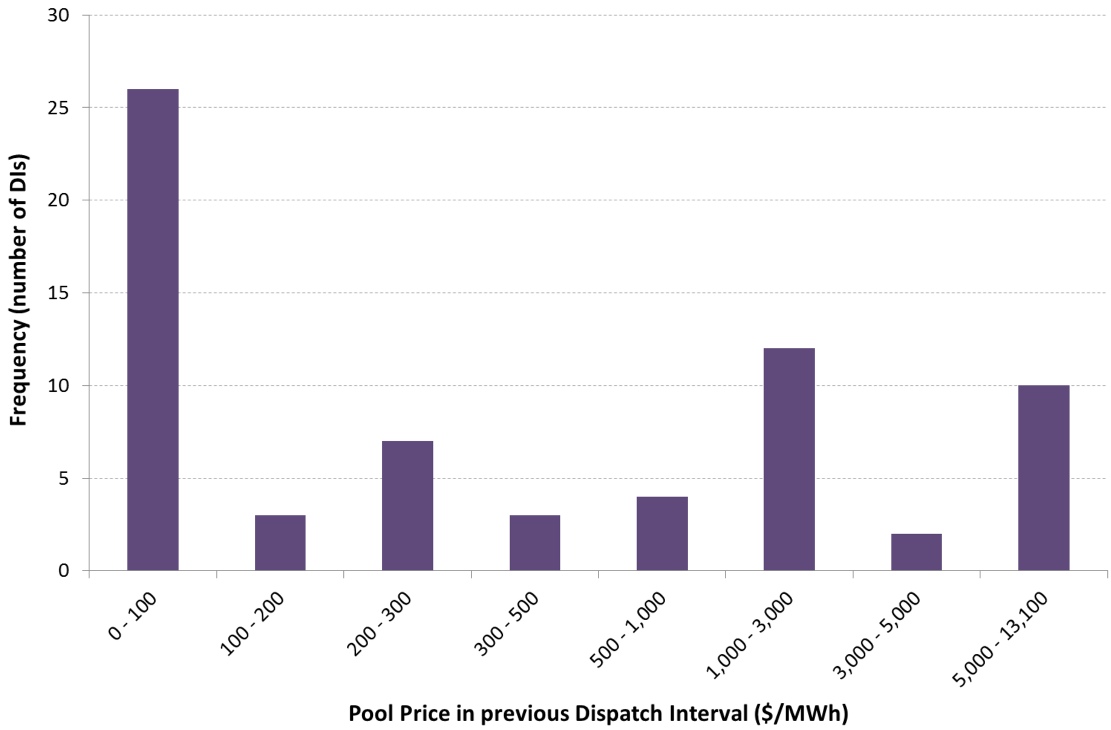

Figure 9.4 – Price in Dispatch Interval prior to price spike events - Queensland

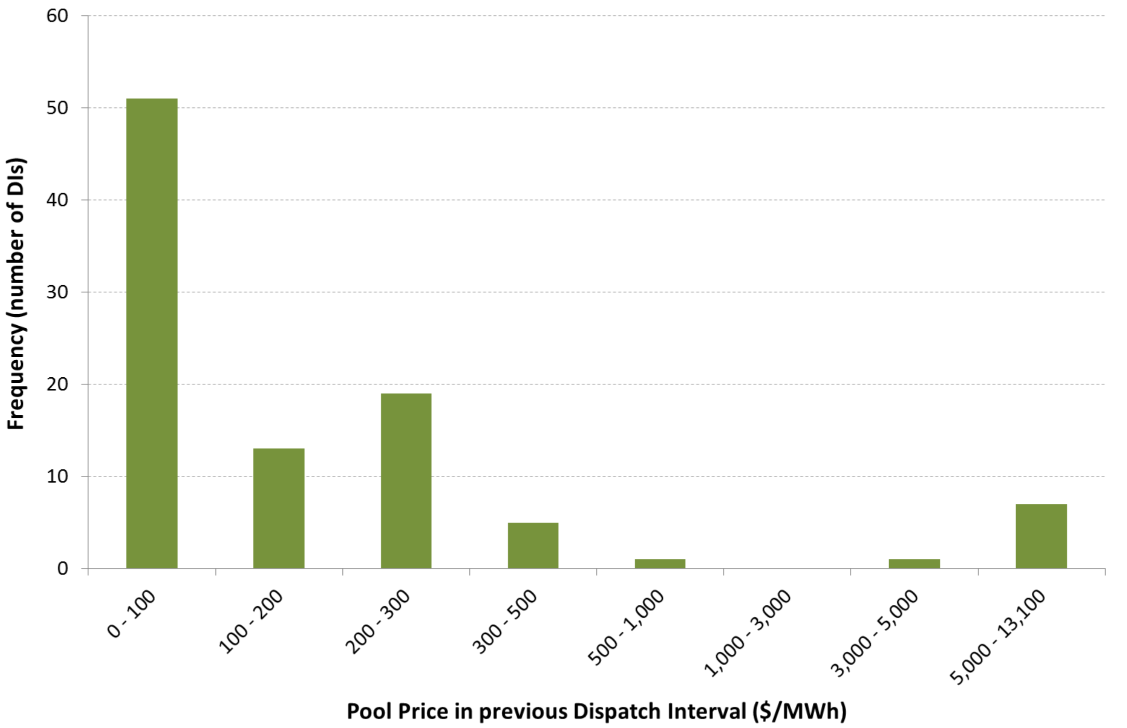

Figure 9.5 – Price in Dispatch Interval prior to price spike events – South Australia

This analysis suggests that a higher MPC will not always result in more profitable outcomes for new entrant OCGT generation. Historical analysis indicates that short-term price volatility may occur that an OCGT may not capture. This can result in a significant loss to an OCGT operating under a cap contract which must pay the difference between the resulting trading interval price and the cap strike price.

9.1.5 Market Impacts for Consumers

A lower MPC, all else being held constant, reduces the price of energy for consumers. Figure 9.6 shows the difference in total revenue paid to generators when the MPC is lowered from $13,100/MWh to $9,000/MWh in the market with 0.002% expected USE. It shows that in this market, generators in all regions – but particularly in Queensland – would earn substantially lower revenue to the benefit of market customers. However, these outcomes are dispatch outcomes for two markets with the same level of capacity. Therefore, the pool price impact of additional generation investment that may be incentivised to enter the market under an MPC of $13,100/MWh compared to the lower MPC of $9,000/MWh is not considered. Consideration of this additional investment would reduce the difference in consumer cost. Moreover, it should be noted that a market with 0.002% USE is not expected within the modelling horizon.

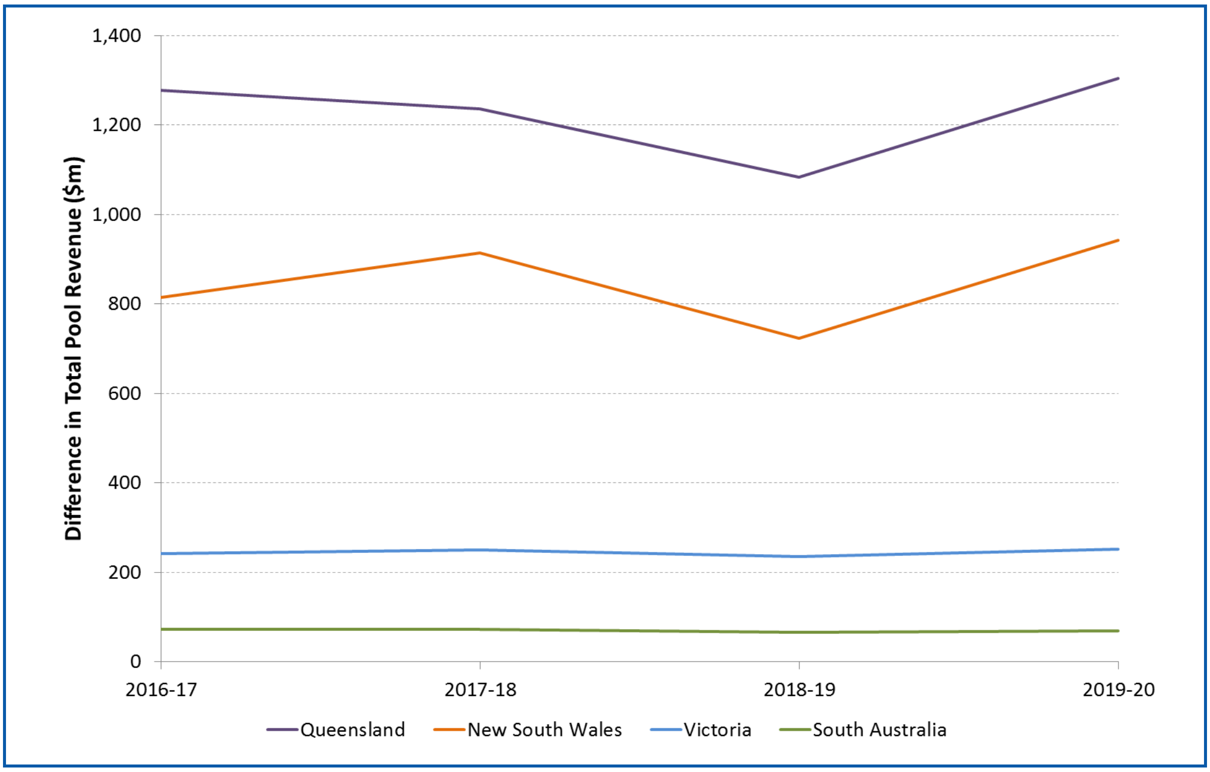

Figure 9.6 – Difference in Total Pool Revenue when MPC Lowered from $13,100 to $9,000 – Market with 0.002% Expected USE

In a market more representative of a likely future, the difference in total revenue paid to generators when the MPC is lowered from $13,100/MWh to $9,000/MWh is shown in Figure 9.7. Queensland market customers still stand to benefit from the lower MPC more than customers in other regions, but the margin is much narrower than in the 0.002% market. Any additional new entry plant in Queensland in excess of the 250 MW CCGT assumed to enter in 2019-20 would reduce this margin. The new entrant CCGT is observed to be significantly more profitable with an MPC of $13,100/MWh. Therefore, by incorporating the effect of the difference in MPC on capacity investment, the difference observed in Figure 9.7 would reduce.

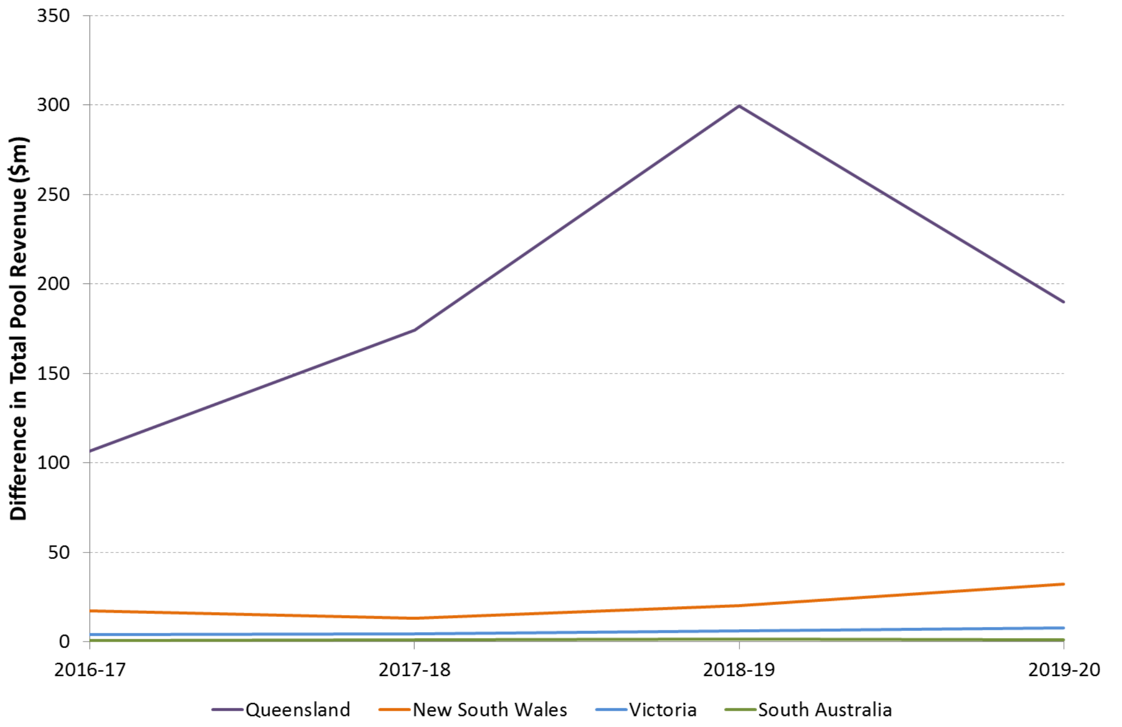

Figure 9.7 – Difference in Total Pool Revenue when MPC Lowered from $13,100 to $9,000 – Minimal Retirement Market

9.1.6 Prudential Requirements

The National Electricity Rules (NER) specify prudential requirements to place a maximum limit on the accumulated amount a participant can owe to or be owed by AEMO in performing their market clearing functions. A trading limit is set as the maximum credit limit minus the prudential margin which is defined by a complex yet well defined set of formulae.

Qualitatively, it is evident that a change in the reliability settings will at some stage in the future change the prudential requirement and credit limit for both generators and customers operating in the NEM. All else being equal, an increased MPC will increase prudential requirements and vice versa. The CPT setting provides a market instrument for mitigating the risk to market participants of extended periods of extreme market prices. Section 5.3 illustrates that there is a strong relationship between MPC and CPT in a market which is delivering near to the reliability standard. However, there will be a relatively weaker link between these market elements in a market with higher capacity reserves.

The quantitative calculation for determining the value impact of prudential requirements on each individual participant also depends on the volume and pricing of contracting. A quantitative assessment of the potential impacts of changes in the MPC and CPT settings has not been completed in this review; however, the issue has been identified in previous reviews and the same considerations should apply in this review.

9.2 *Market Participant Behaviour*

9.2.1 Impact on Portfolios

A higher MPC value creates an increased incentive for generation portfolios to exercise transient market power. The withdrawal of capacity can potentially result in prices at the higher MPC and increases the likelihood of a profitable price volume trade-off. ROAM has conducted quantitative modelling to assess the materiality of this effect for MPC values of $9,000/MWh and $13,100/MWh.

Pool Price Volatility Outcomes

In a market in which pool prices reach the MPC, an increase in the MPC will result in an increase in pool price volatility. This increase occurs as pool prices which were previously $9,000/MWh would likely reach $13,100/MWh.[26] ROAM has examined our dispatch modelling outcomes to determine whether additional volatility occurs with an MPC of $13,100/MWh relative to $9,000/MWh as a result of the impact of MPC on incentives to engage in strategic bidding. Such an outcome is demonstrated by a period where pool price did not exceed $9,000/MWh in the low MPC scenario and where price did exceed this value in the high MPC scenario. This demonstrates that the increased MPC has provided an incentive for a withdrawal of capacity which was not sufficient in the low MPC scenario.

This analysis has been applied to both the minimal retirement market and the 0.002% expected USE market. The 0.002% USE scenario provides an upper bound for the impact of the MPC on participant behaviour. A more likely outcome is provided in the minimal retirement scenario; although neither scenario incorporates the possible impact of the MPC on five-minute dispatch which may also influence participant behaviour. This analysis also excludes the application of the CPT. Alternative levels of MPC and CPT result in a change in the frequency of APC periods which clouds any analysis of the direct impact of MPC on participant behaviour.

Table 9.1 shows the additional pool price volatility that occurs from increasing the MPC. This table illustrates that the higher MPC of $13,100/MWh has increased the frequency of prices above $9,000/MWh. This is particularly true in the market which experiences significant USE. In the minimal retirement market, there is insufficient volatility in New South Wales, Victoria and South Australia for the increase in MPC to impact on participant behaviour. Similarly, the impact in the 0.002% USE market is most prominent in Queensland and New South Wales which were shown to be the most volatile regions for a given MPC (see Section 5.1.3).

The increased number of periods in which the pool price exceeds $9,000/MWh must result from a commensurate reduction in the frequency of prices below this value. These

[26] This excludes the impact of some other market factors which may help to mitigate price rises associated with an increased MPC such as additional DSP.

reductions are observed to occur at a range of prices between \$300/MWh and \$9,000/MWh.

Table 9.1 – Additional hours of prices > \$9,000/MWh for MPC of \$13,100/MWh compared to \$9,000/MWh

	QLD		NSW		VIC		SA	
	0.002%	**Minimal Retire.**	**0.002%**	**Minimal Retire.**	**0.002%**	**Minimal Retire.**	**0.002%**	**Minimal Retire.**
2016-17	4.2	0.8	3.5	-	1.1	-	1.1	-
2017-18	5.0	1.2	3.9	-	1.1	-	1.1	-
2018-19	3.8	2.2	3.1	-	0.9	-	0.9	-
2019-20	4.5	1.3	4.3	-	1.1	-	1.1	-

These results show that even in the most extreme market, the impact of the MPC on portfolio bidding behaviour is relatively minor. The analysis suggests that the incentive to withdraw capacity with an MPC of \$13,100/MWh is likely to still be present when an MPC of \$9,000/MWh is applied. This is particularly true of a market which is relatively oversupplied with capacity.

9.2.2 Impact on Demand Side Participation

In all stages of the modelling, ROAM has assumed that the level of DSP available is constant. A reduction in the MPC may reduce the incentive for participants to engage in demand management activities. ROAM illustrated in Section 5.8 that a reduction in DSP results in a need for an increased MPC to meet the reliability standard. Therefore the level of MPC and the quantity of DSP which is provided in the market are closely related.

The DSP assumptions used by ROAM in this study are provided by AEMO. These assumptions provide three DSP pool price trigger points. The highest of these trigger points is assumed to be the MPC of \$13,100/MWh. There is insufficient information available in the public domain to forecast the amount of DSP which may be available if the MPC was reduced.

ROAM has conducted additional sensitivity testing for Stage 1 by removing the quantity of DSP that becomes available when the pool price reaches \$13,100/MWh. The resulting MPC requirement in South Australia in these studies exceeded the current MPC. With more detailed DSP data, an equilibrium between the MPC and DSP could be reached. However, such information is not available at this time. Any consideration of a change in DSP should take into account the impact this change may have on DSP and therefore, reliability.

9.3 INTERCONNECTION

9.3.1 Negative Settlements Residues

Negative settlements residues occur when electricity flows from a higher-price region to a lower price region. These flows are called counter-price flows. Counter-price flows are primarily the result of intra-regional transmission issues. Counter-price flows also occur as a result of dispatch process errors and pricing and metering issues[27]. Negative settlements residues are recovered through network charges to consumers. There is currently no mechanism that allows consumers to hedge against the cost of negative settlements residues[28].

To investigate the potential impact of an alternative MPC on the level of negative settlements residues, ROAM conducted a historical analysis of market data for the 2011-12 and 2012-13 financial years. We replicated the settlement residue calculation in each trading interval to determine the quantity of negative settlements residues that have occurred under the existing reliability settings. An additional calculation has been performed to apply a lower MPC value in the dispatch interval outcomes. This calculation excludes any impact that the alternative MPC would have on the market. Rather, historical pool prices are capped at the lower MPC value.

Table 9.2 shows the reduction in negative settlements residues over this period where an MPC of $9,000/MWh is applied. This data shows that the lower MPC value leads to a material reduction in the negative settlements residues which historically accrued across some NEM interconnectors. This analysis has not considered the potential impact of a lower MPC on the implementation of clamping by AEMO.

[27] AEMO, November 2011, *Guide to the Settlements Residue Auction*. Available at: http://www.aemo.com.au/Electricity/Market-Operations/Settlement-Residue-Auction/Guide.

[28] AEMC, October 2013, *Management of negative inter-regional settlements residues.* Available at: http://www.aemc.gov.au/market-reviews/open/management-of-negative-inter-regional-settlements-residues.html

Table 9.2 – Reduction in Negative Settlements Residues – 2011-12 and 2012-13

	Reduction in NSRs ($)		Reduction in NSRs (%)	
Interconnector	**2011-12**	**2012-13**	**2011-12**	**2012-13**
NSW -> QLD	$0	$0	-	-
QLD -> NSW	$627,137	$629,330	9%	5%
VIC -> NSW	$0	$631,759	-	27%
NSW -> VIC	$442,699	$0	26%	-
VIC -> SA	$0	$31,767	-	6%
SA -> VIC	$116,961	$44,843	15%	13%
Total	$1,186,796	$1,337,699	12%	8%

9.3.2 Inter-regional Trading

Section 9.1.3 provides an analysis of the relationship between the MPC and contract markets. That analysis focused on participants contracting within the region that they are located. Market participants are also able to trade financial contracts that are settled in regions other than the region in which the participant is located. For example, a New South Wales generator may sell a futures contract in Queensland. Inter-regional trade creates an additional risk for participants called basis risk. Basis risk occurs because the commodity that is being hedged is not equivalent to the asset being physically sold or purchased by the participant.

AEMO operates the Settlements Residue Auction as a means for market participants to purchase inter-regional settlement residues (IRSRs). These IRSRs provide some level of hedging against basis risk for counter-parties engaged in inter-regional hedging. However, given that interconnectors are often unable to flow at their maximum capacity between regions when price separation is occurring, IRSRs provide only a partial hedge of basis risk. The principle of “firmness” refers to the proportion of this risk that IRSRs are able to adequately hedge against. This lack of firmness reduces the liquidity of inter-regional trading in the NEM.

It is clear that there is a relationship between the MPC and inter-regional basis risk. A higher MPC will tend to increase the potential for price separation between two regions. The level of inter-regional contracting that occurs in the NEM is not publicly available. ROAM has however performed historical analysis of inter-regional trading for the 2011-12 and 2012-13 financial years. This analysis aims to quantify the impact of the MPC on inter-regional basis risk and to determine whether the MPC has any effect on the firmness provided by IRSRs.

For the historical period of interest, ROAM has calculated the value of IRSRs for each of the directional, regulated interconnectors in the NEM. This value has been recalculated with the assumption that dispatch interval pool prices are capped at the lower MPC of $9,000/MWh. Similarly, the IRSRs have been calculated assuming that the full value of inter-regional price separation is realised by the IRSRs; that being where interconnectors flow at the "maximum units" quantity specified in the Settlement Residue Auction Rules[29] and in the direction of higher prices.

Table 9.3 shows the full value of price separation assuming that interconnectors were able to flow at their maximum units quantity. This value can be interpreted as a proxy for the upper bound of basis risk in the NEM. This table demonstrates that a reduction in MPC results in a material reduction in the level of possible basis risk in the NEM. This is particularly true of 2012-13 where much of the price volatility, particularly in Queensland and South Australia, resulted from single dispatch intervals at or near the MPC of $13,100/MWh.

Table 9.3 – IRSR Value assuming Interconnectors flow at Maximum Units Quantity ($m)

	2011-12			2012-13		
	MPC: $13,100	MPC: $9,000	Reduction	MPC: $13,100	MPC: $9,000	Reduction
SAVIC	19.3	19.3	0.0	29.6	23.5	6.2
VICSA	50.9	46.9	3.9	160.4	144.0	16.4
VICNSW	33.1	32.0	1.1	32.1	32.1	0.0
NSWVIC	7.9	7.9	0.0	56.5	47.0	9.5
NSWQLD	18.8	17.4	1.4	148.4	140.1	8.3
QLDNSW	25.3	24.6	0.7	23.1	23.1	0.0
Total	**155.2**	**148.2**	**7.1**	**450.2**	**409.9**	**40.4**

Table 9.4 show ROAM's assessment of historical IRSR settlements. These results also show that a reduction in MPC reduces the value of IRSRs for holders of those instruments.

[29] AEMO, January 2011, *Settlement Residue Auction Rules*. Available at: http://www.aemo.com.au/Electricity/Market-Operations/Settlement-Residue-Auction/Rules.

Table 9.4 – Realised IRSR Values ($m)

	2011-12			2012-13		
	MPC: $13,100	MPC: $9,000	Reduction	MPC: $13,100	MPC: $9,000	Reduction
SAVIC	3.1	3.1	0.0	7.2	5.4	1.8
VICSA	12.7	11.5	1.2	45.1	40.4	4.6
VICNSW	14.6	14.6	0.0	10.0	10.0	0.0
NSWVIC	0.8	0.8	0.0	8.2	7.1	1.1
NSWQLD	0.7	0.6	0.1	15.5	14.7	0.8
QLDNSW	15.0	14.4	0.6	15.4	15.4	0.0
Total	**46.9**	**45.0**	**1.8**	**101.3**	**93.0**	**8.3**

Table 9.5 shows the results of ROAM's assessment of the firmness of IRSRs. From these results it is evident that the IRSRs do not provide a firm hedge against basis risk between a number of region pairs in the NEM. There is also limited evidence that the MPC has a strong relationship with the firmness of IRSRs, as shown in Table 9.5 which shows a minimal and inconsistent reduction in the realised value of IRSR units as a proportion of their hypothetical maximum value. The relationship between MPC and IRSR firmness relates to the capacity of an interconnector to transfer energy in periods where price is at the MPC. This historical period represents a relatively small sample size in this regard.

Table 9.5 – IRSR Firmness (%)

	2011-12			2012-13		
	MPC: $13,100	MPC: $9,000	Reduction in Firmness	MPC: $13,100	MPC: $9,000	Reduction in Firmness
SAVIC	16.1%	16.1%	0.0%	24.2%	23.0%	-1.2%
VICSA	24.9%	24.5%	-0.4%	28.1%	28.1%	0.0%
VICNSW	44.2%	45.7%	1.5%	31.2%	31.2%	0.0%
NSWVIC	10.0%	10.0%	0.0%	14.6%	15.1%	0.5%
NSWQLD	3.7%	3.6%	-0.1%	10.4%	10.5%	0.1%
QLDNSW	59.3%	58.7%	-0.7%	66.4%	66.4%	0.0%
Total	**30.2%**	**30.4%**	**0.2%**	**22.5%**	**22.7%**	**0.2%**

Therefore there is some evidence that a reduction in MPC could lead to a reduced basis risk and therefore increase the ability for participants to hedge across regional boundaries. There is not sufficient evidence to suggest that a reduction in MPC will increase the firmness of IRSRs as a means of mitigating this basis risk.

10 SUMMARY

This report has presented outcomes of quantitative modelling conducted to investigate the reliability standard and settings and their potential impact on generation capacity investment signals in the NEM. The primary focus of the report was to illustrate the outcomes of ROAM's modelling in determining the MPC required to allow new entrant generation to profitably operate in a market which just achieves the reliability standard. The report presented outcomes of two approaches to this analysis:

- The cap defender approach provides an assessment of the MPC which incorporates market pricing outcomes as a driver for investment in OCGT generation;
- The extreme peaker approach provides a theoretical upper estimate of the MPC requirement by restricting the operation of the new entrant to only periods of USE.

The cap defender outcomes indicate that under Base Case assumptions that the MPC required to incentivise investment in OCGT capacity is below the current MPC of $13,100/MWh. However, the existing MPC setting does fall within the range of sensitivity outcomes. Further analysis supports this outcome in demonstrating that the current reliability settings are sufficient to achieve the reliability standard over a 10 year period.

ROAM has also provided quantitative modelling to inform the panel of the appropriateness of the existing reliability standard and the market floor price setting.

It is important to acknowledge that the level of the reliability settings have impacts on a range of market participants in the NEM. These impacts reach beyond a pure assessment of reliability outcomes. In light of this, ROAM has provided quantitative and qualitative analysis of a range of issues related to the non-reliability impacts of the reliability settings.

Appendix A BENCHMARK OUTCOMES

ROAM has performed a benchmark of the modelling completed during the 2010 Reliability Standard and Settings Review. As part of this benchmark, ROAM replicated the extreme peaker methodology applied in the 2010 Review. The results of this approach are comparable to the 2010 Review outcomes (see Figure A.1).

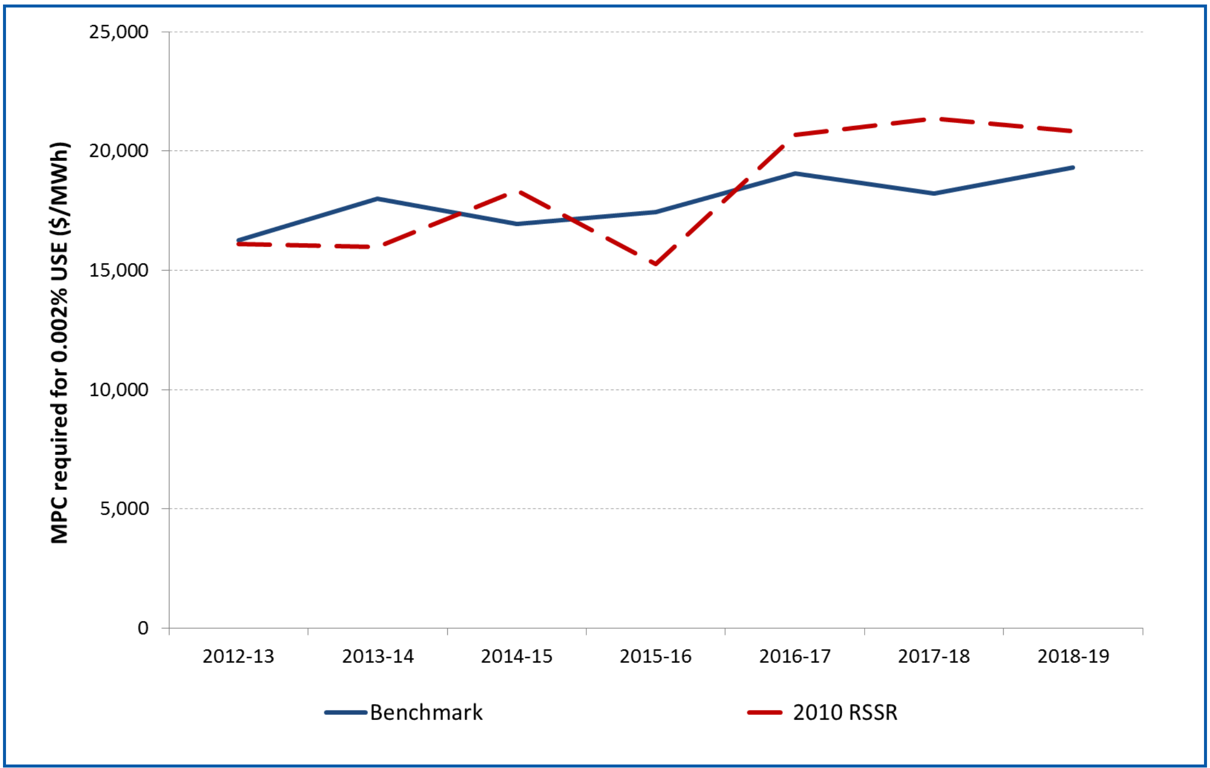

Figure A.1 – Extreme Peaker Benchmark Outcomes

ROAM has also applied the cap defender methodology in the benchmark exercise. The outcomes of this approach are provided in Figure A.2. It is evident that the cap defender approach results in a lower MPC requirement than the extreme peaker approach. It is also evident that there is significant disparity between the MPC values required in each region to achieve the reliability standard. The reasons for these differences are analysed in detail in Section 5.1.3.

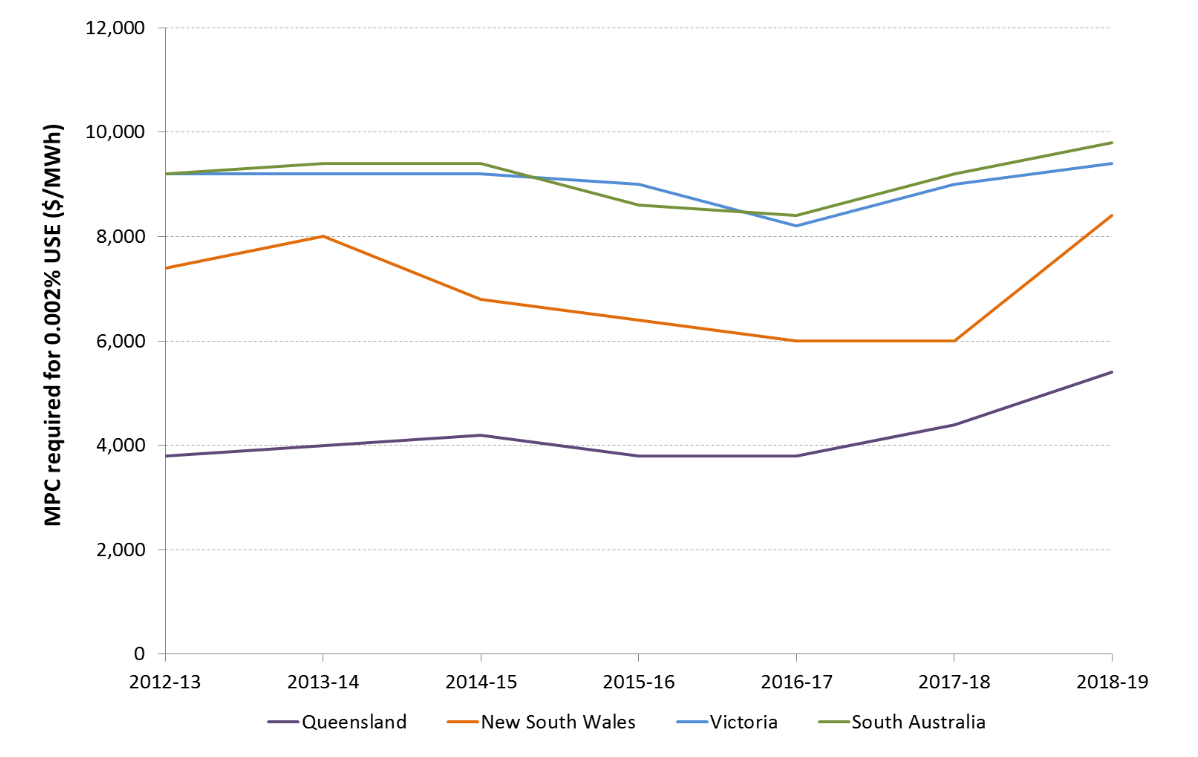

Figure A.2 – Cap Defender Benchmark Outcomes

Appendix B MULTIPLE REFERENCE YEAR APPROACH

The importance of the reference year to reliability modelling is illustrated in the following figures. Figure B.1 shows the demand distribution in Queensland in 2016-17 for each of the reference years 2008-09 to 2012-13. It is evident that there is a wide range in the shape of the demand peak in recent years. For example, in 2009-10, the demand exceeded 95% of the regional peak in over 0.3% of periods. However, in 2010-11, this percentage fell to below 0.1%. A narrow peak such as that observed in 2010-11 increases the cost of additional reliability. An illustration of the peak load durations is also provided for Victoria in Figure B.2.

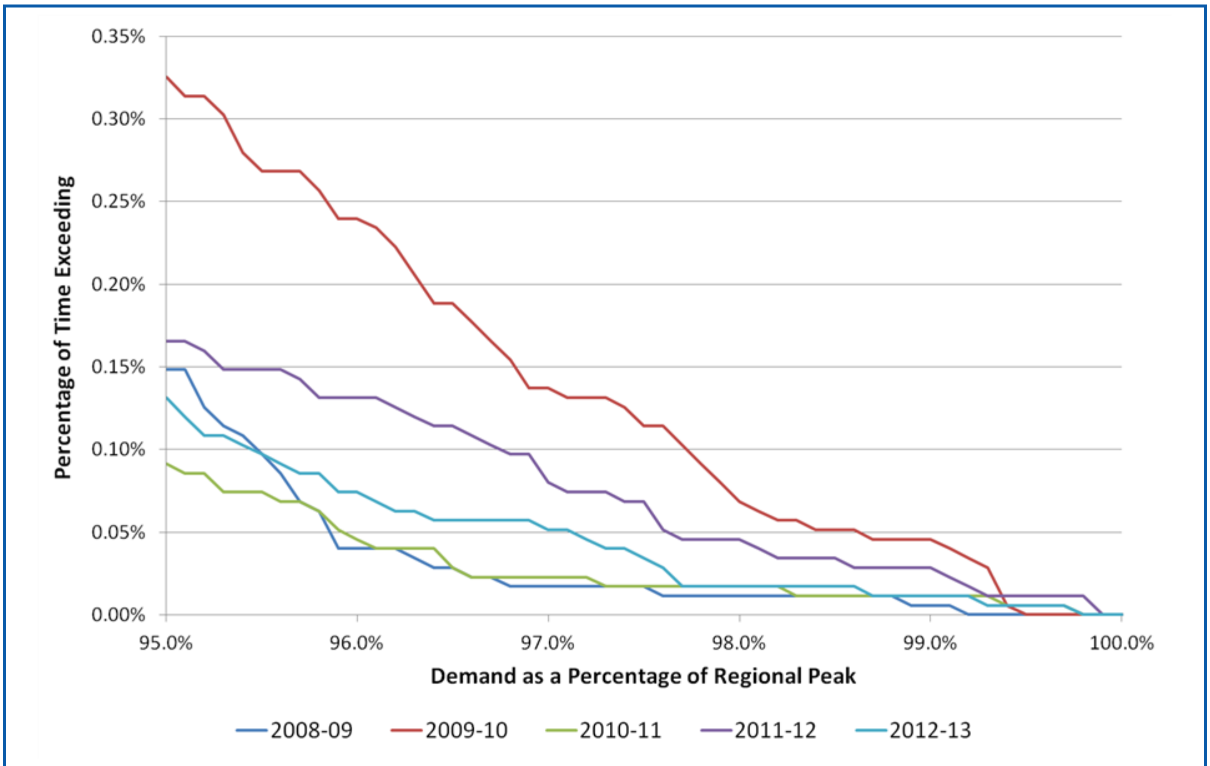

Figure B.1 – Peak Load Duration in Queensland in 2016-17 for Reference Years 2008-09 to 2012-13

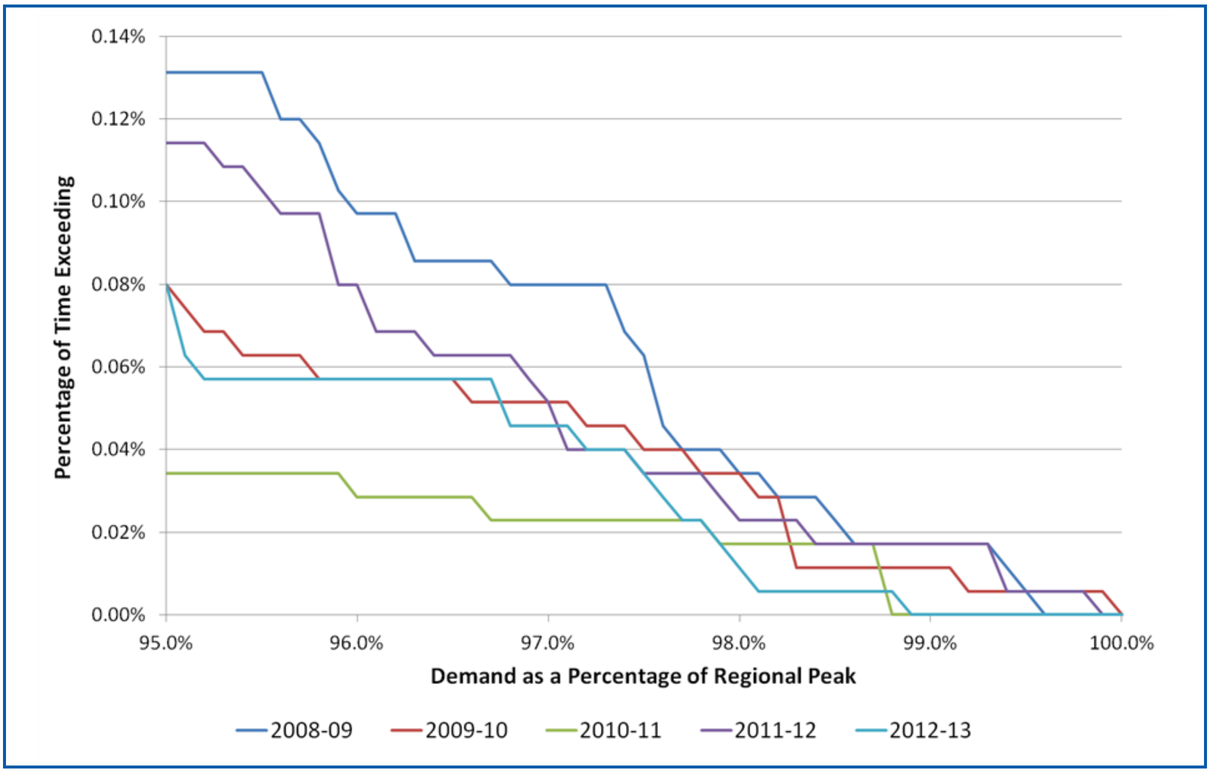

Figure B.2 – Peak Load Duration in Victoria in 2016-17 for Reference Years 2008-09 to 2012-13

In this review, ROAM conducted modelling using the five reference years, 2008-09 to 2012-13, to incorporate a range of possible demand distributions in the modelling reflective of the most recent historical observations. The results from the five reference years were equally weighted in all reliability and MPC calculations.

ROAM also modelled the variable nature of wind and solar generation (both large-scale and distributed PV). Generation in each future study year was calculated based on meteorological conditions across the NEM in each historical reference year and the installed capacity and location of wind and solar generators in the study year. This method allowed ROAM to preserve the intermittency and shape of renewable generation and its correlation with energy consumption.

The use of five reference years is an improvement on the 2010 RSSR studies conducted by ROAM which used a single reference year, 2008-09, as the reference load trace.

Appendix C ROOFTOP PV ASSUMPTIONS

ROAM has used the moderate growth projection for distributed PV from the 2013 NEFR in all modelling. Projected capacity is shown in Figure C.1.

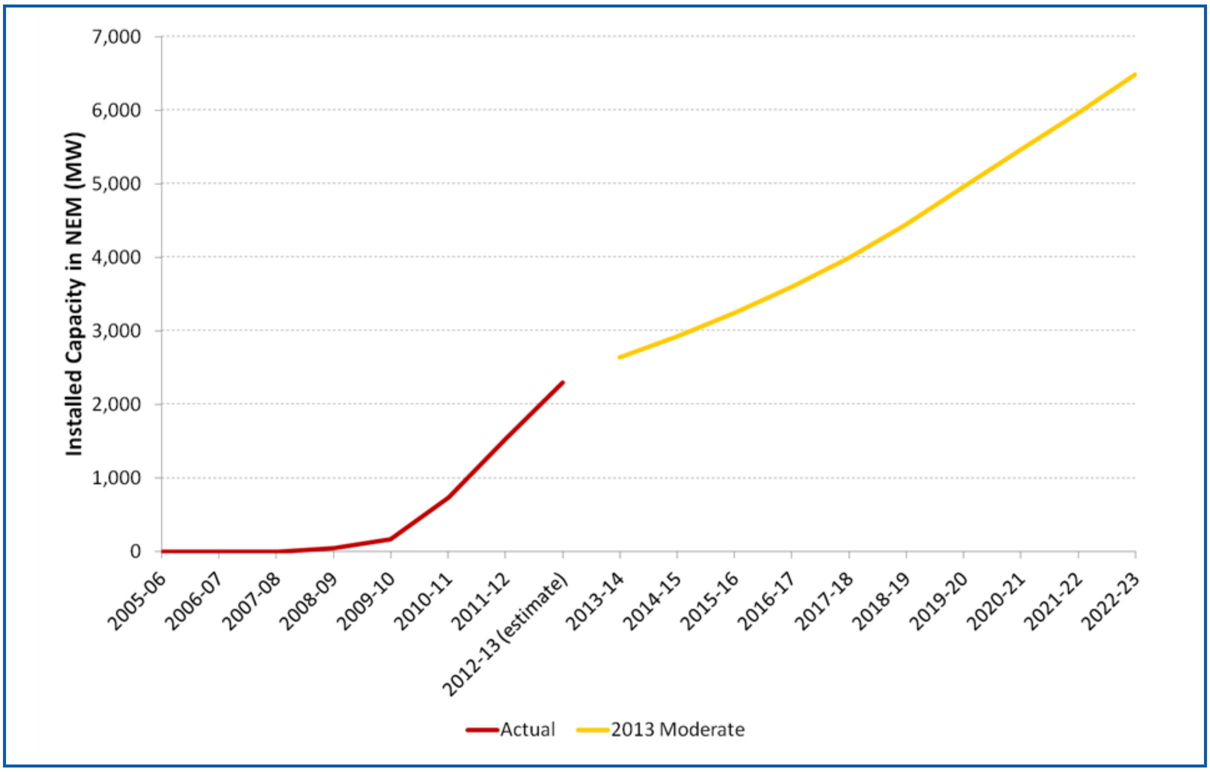

Figure C.1 – NEM Rooftop PV Capacity

ROAM explicitly incorporated generation by distributed PV into modelling by taking the projected capacity of distributed PV in each region and calculating the corresponding generation traces for each half-hourly trading interval using historical solar irradiation data. This process was completed for each of the five reference years. Using this method, the intermittency and shape of rooftop PV generation and its relationship with wind and large-scale solar generation and energy consumption is preserved.

ROAM considered the possibility of an additional scenario to investigate the potential impact of the LNP policy of an "additional million solar roofs". Given that the projection used has an almost 130% increase in generation from distributed solar PV compared to 2012-13 levels, and in the absence of policy detail, ROAM assumed this new possible policy would not deliver additional growth.

Appendix D LARGE-SCALE RENEWABLE ENERGY TARGET

D.1 REDUCED LRET CALCULATION

For the Reduced LRET sensitivity, ROAM calculated 20% of the current forecast of Australia-wide energy consumption in 2020. According to the calculations in Table D.1, this corresponds to approximately 29 TWh of new renewable generation by 2020 across Australia (27 TWh of LRET liability, and 2 TWh of Green Power liability).

Table D.1 – Calculation of LGC Liability in Reduced LRET Sensitivity

	Source	Value in 2020
Native annual energy in NEM (GWh)	AEMO NEFR 2013	209,984
Rooftop PV in NEM (GWh)	AEMO NEFR 2013	6,449
Total energy demand in NEM (GWh)	Native energy + Rooftop PV	216,443
NEM share of Australia-wide energy consumption	AEMO Planning Assumptions 2013	86.3%
Total energy demand in Australia (GWh)	NEM energy/NEM share	250,791
20% of energy (GWh)	Total energy x 20%	50,158
Energy from pre-existing hydro (GWh)	MRET Baseline	15,000
SRES contribution (GWh)	AEMO NEFR 2013 + non-NEM contribution	8,000
LRET liability (GWh)	20% of demand – existing hydro – SRES	27,158
LGC demand from desalination	AEMO Planning Assumptions 2013	0
LGC demand from Green Power	AEMO Planning Assumptions 2013	2,082
Total LGC liability	LRET + desalination + Green Power	29,240

D.2 LARGE-SCALE RENEWABLE DEVELOPMENT PLANS

ROAM closely monitors the status of renewables projects that presently and may in the future contribute to meeting the LRET. The build schedule of large-scale renewables used to meet an LRET of 41 TWh is shown in Figure D.1, while the build schedule to meet the Reduced LRET is shown in Figure D.2. We have maintained a similar proportion of wind development in the NEM and the SWIS in the two LRET scenarios.

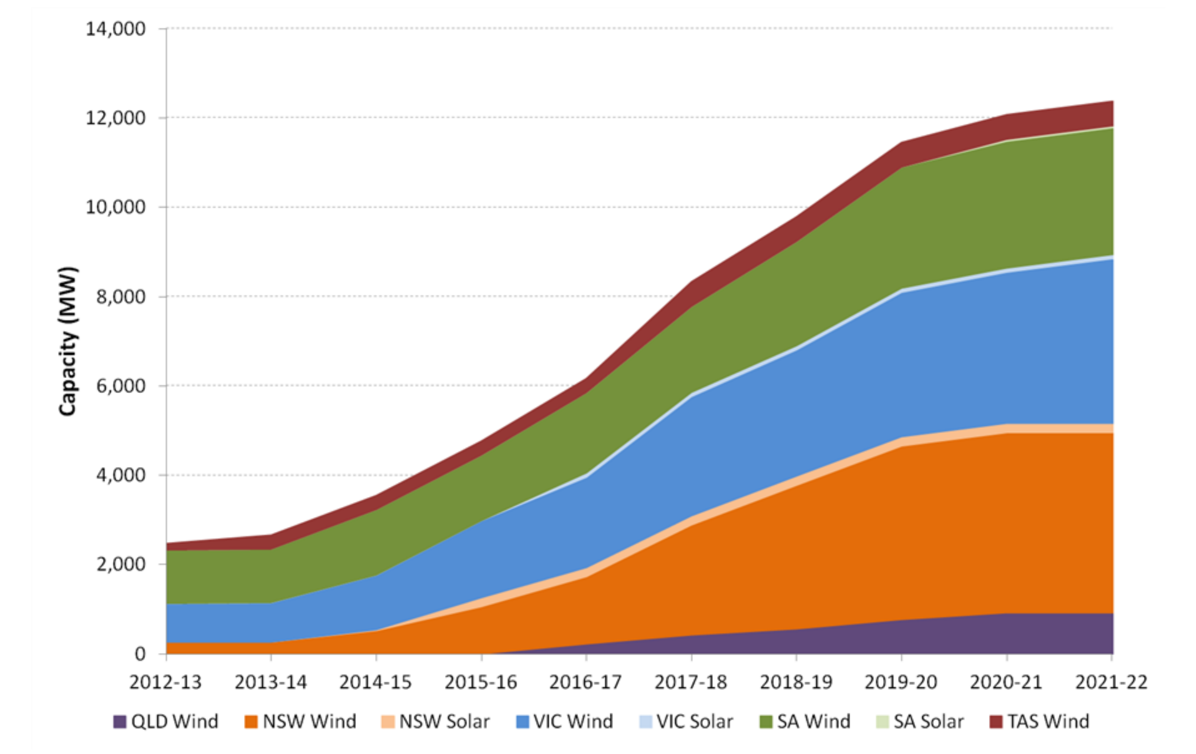

Figure D.1 – Large-scale Renewable Development Under Central LRET Assumptions

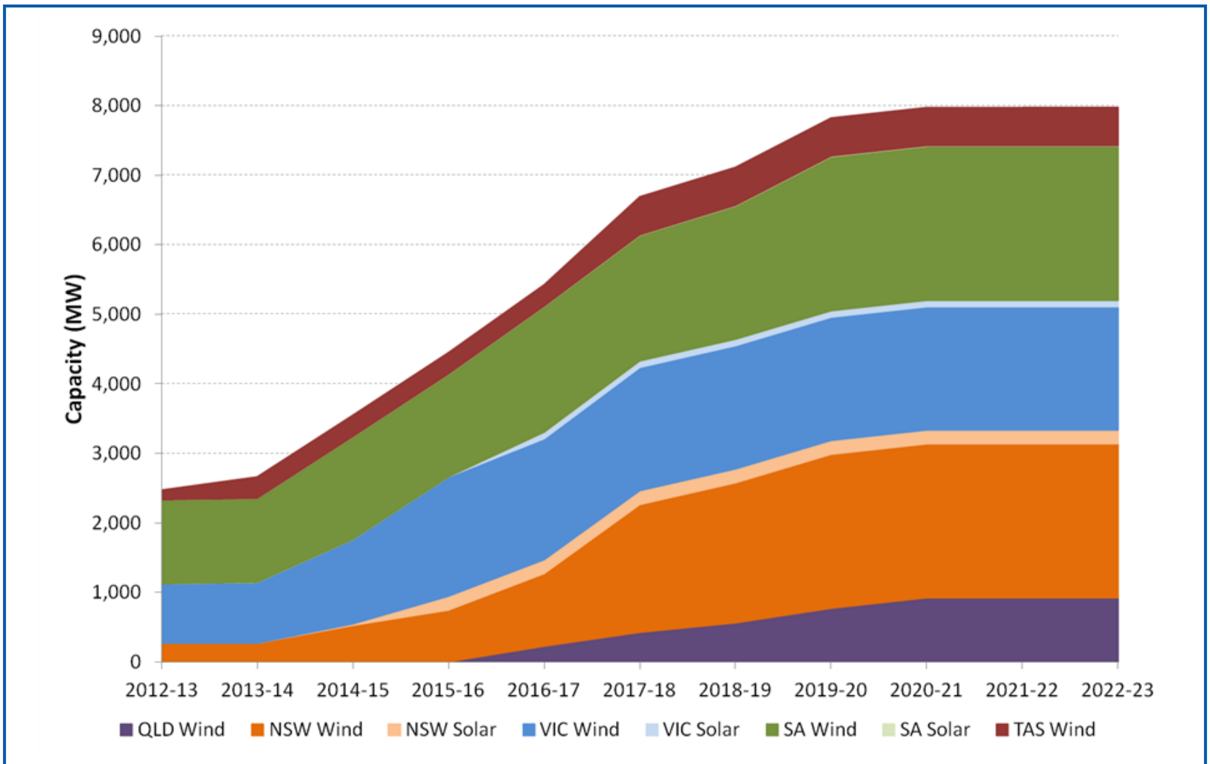

Figure D.2 – Large-scale Renewable Development Under Reduced LRET Assumptions

We note that the build rates required to meet the central LRET trajectory are significant; 9.4 GW of wind is installed across the NEM by the end of the study period in addition to the 2.7 GW already installed, representing a 4.5-fold increase in wind capacity. However, ROAM estimates that there is already 1.4 GW of wind capacity under construction and a further 3.7 GW of wind capacity approved for construction in the NEM. Hence, a further 4.0 GW of wind generation would need to be built on top of already approved projects. Overall, this trajectory requires a peak build rate of approximately 1.7 GW/annum sustained over the period from 2016-17 to 2019-20.

The Reduced LRET trajectory is less ambitious but still represents a significant increase in wind capacity. It requires approximately 5 GW of wind to be installed across the NEM by the end of the study period representing a 2.8-fold increase in wind capacity. This total can be met by the wind farms currently under construction and approved for construction.

ROAM's analysis suggests that both the existing legislated LRET and the Reduced LRET are challenging, but achievable. Under both scenarios, the regional annual build rates and total wind penetration levels fall within the limits published by AEMO in the 2013 Planning Assumptions. Moreover, they are in line with international levels already being achieved on a population pro-rata basis.

Appendix E OCGT Annualised Capital Cost

Recent estimates of OCGT capital costs were sourced from the Bureau of Resources and Energy Economics[30] (BREE), the West Australian Independent Market Operator[31] (IMO) and the AEMO Planning Assumptions for 2013[32]. ROAM was advised by the Reliability Panel that a twenty year lifetime is appropriate from a financial perspective for a new entrant OCGT. On this basis, the annualised capital costs including connection costs based on the three data sources evaluates to approximately $100,000/MW/annum, as shown in Table E.1. All data extracted from these references has been converted to June 2013 dollars.

Table E.1 – Annualised Capital Cost Calculations

	IMO	BREE	NTNDP
Capital Cost of Generation ($/MW)	$1,032,500	$744,378	$742,899
Connection Cost ($/MW)	$113,488	$110,000	$110,000
Total Capital Cost ($/MW)	$1,145,987	$854,378	$852,899
WACC (pre-tax real)	5.95%	10%	9.79%
Term of Finance (Years)	20	20	20
Annualised Capital Cost ($/MW/a)	$99,535	$100,355	$98,749

[30] Bureau of Resources and Energy Economics, 2012, *Australian energy technology assessment*. Available at: http://www.bree.gov.au/publications/aeta.html. Accessed: 15th August 2013.

[31] Independent Market Operator, January 2013, *Final report: maximum reserve capacity price for the 2015/16 capacity year*. Available at: http://www.imowa.com.au/mrcp. Accessed: 15th August 2013.

[32] Australian Energy Market Operator, June 2013, *2013 Planning Assumptions: Existing Generation Data*. Available at: http://www.aemo.com.au/Electricity/Planning/Related-Information/2013-Planning-Assumptions. Accessed 16th August 2013.

Appendix F DSP CAPACITY

Table F.1 – Summer DSP Assumptions Provided in the AEMO NEFR 2013

Region	Price ($/MWh)	Capacity (MW)			
		2016-17	2017-18	2018-19	2019-20
Queensland	≥ 1,000	58	62	66	70
	≥ 7,500	70	75	80	85
	MPC	148	158	169	180
New South Wales	≥ 1,000	21	23	24	26
	≥ 7,500	56	60	64	68
	MPC	195	209	224	238
Victoria	≥ 1,000	121	124	127	130
	≥ 7,500	259	265	271	277
	MPC	453	463	474	485
South Australia	≥ 1,000	34	36	37	39
	≥ 7,500	41	43	45	47
	MPC	72	75	78	81
Tasmania	≥ 1,000	3	3	3	3
	≥ 7,500	37	38	38	38
	MPC	67	68	69	69

Quantities in each band are cumulative. For the DSP sensitivity quantities in each price band are reduced by 50% (Section 4.6.6).

Appendix G DYNAMIC BIDDING METHODOLOGY

ROAM has applied a portfolio-based dynamic bidding approach in all stages of the review, including the benchmark. ROAM's dynamic bidding application is a turn-based approach which optimises the bidding strategy of each portfolio subject to the bidding strategies of all other portfolios in each trading interval. This turn-based approach iteratively determines a Nash equilibrium in which no portfolio benefits from changing its bidding strategy. This approach accounts for the marginal cost of all generation in the portfolio and the assumed contacting position of each portfolio. Table G.1 provides a summary of the portfolios used by ROAM in modelling competition in the NEM.

Table G.1 – Generation Portfolios

Region	Portfolios
Queensland	CS Energy
	Stanwell
New South Wales	Macquarie Generation
	Origin Energy
	Delta Electricity
	EnergyAustralia
Victoria	AGL
	EnergyAustralia
	GDF Suez
South Australia	Origin Energy
	AGL
	GDF Suez

ROAM assumes that new entrant generation does not belong to a particular portfolio. Therefore, ROAM assumes that all new entrant generation will bid at short-run marginal cost (SRMC).