100% Renewables in Australia

Will a Capacity Market be Required?

Jenny Riesz, Iain MacGill
Centre for Energy and Environmental Markets , University of NSW, Sydney, Australia
j.riesz@unsw.edu.au, i.macgill@unsw.edu.au

***Abstract*—Efficient wholesale markets should drive preference revealing bidding where generators offer the majority of their power at short run marginal cost (SRMC). However, most renewables have very low SRMCs, which in a competitive market is likely to lead to an increasing proportion of low priced periods. This has led to suggestions that a capacity market may be required in the Australian National Electricity Market (NEM). This analysis suggests that existing energy-only market mechanisms in the NEM have the potential to operate effectively in a 100% renewables scenario, but success will rely upon two critical factors: (1) further increase to the already high Market Price Cap (MPC) of $12,900/MWh. Initial analysis suggests this may need to increase by a factor of six to eight. Alternatively, comprehensive demand side participation could allow each customer to select their preferred level of reliability and associated cost, removing the need for an administratively determined MPC. (2) A liquid and well-functioning derivative contracts market, to allow generators and retailers to hedge significant market risks successfully. Observed trends towards vertical integration and market power in retail markets may be reducing derivative market liquidity. Additional transparency measures may be required to facilitate improved monitoring, and intervention may ultimately be required to ensure continued derivative market liquidity.**

Keywords-Capacity market, energy-only market, National Electricity Market, NEM, Australia

I. Introduction

There is increasing interest in understanding how electricity industries may function with very high penetrations of variable renewable energy generation. With increasing pressure to reduce greenhouse emissions, concerns about the longer-term availability and price of fossil-fuels, recent nuclear power setbacks and continued reductions in the costs of some renewable technologies, a shift to power systems with a higher penetration of renewable energy appears inevitable.

The Australian Energy Market Operator (AEMO) recently released detailed modelling suggesting that a 100% renewable generation mix for the Australian National Electricity Market (NEM) is technically feasible at costs that, while higher than present, appear manageable [1]. This is consistent with previous analysis conducted at the University of NSW [2], and by Beyond Zero Emissions with the University of Melbourne [3].

Photovoltaics (PV) and Concentrating Solar Power (CSP) feature prominently in the estimated least cost mix of all these modeling efforts, contributing almost half of generation in some scenarios. This is due to the projected low cost of PV, the value of CSP energy storage, and the abundance of solar resources in Australia. Wind power also features heavily in the scenarios, while renewables with associated energy storage other than CSP include existing hydro power (less than 10% of the current generation mix), biomass and, in some scenarios, engineered geothermal systems.

A key objective of these modeling efforts has been to find least cost renewable mixes that ensure system adequacy by meeting the existing NEM reliability criterion of 0.002% unserved energy. As such, they raise, , but do not themselves address, questions regarding the viability of the existing energy-only wholesale gross pool market arrangements of the NEM with 100% renewables. The analysis presented in this paper aims to explore the issue of system adequacy in a 100% renewables market, meaning the market mechanisms that manage the quantity of installed generating capacity, and the adequacy of this installed capacity to meet anticipated demand. Specifically, we ask whether the present NEM mechanisms for system adequacy are likely to remain sufficient in a 100% renewables system.

Electricity market resource adequacy models have been fiercely debated over the past decade and the issue remains unresolved. Proponents of energy-only market models argue that they avoid the need for increasingly prescriptive regulations, and create better incentives for operations and investment [4, 5]. On the other side, proponents of capacity market models argue that an energy-only market cannot operate satisfactorily on its own; regulatory demand for energy, operating reserves and capacity are required [6, 7]. This paper aims to extend this debate through examination of the energy-only market implemented in the NEM, in the context of very high renewable penetration.

II. The Australian National Electricity Market

The NEM spans the east coast of Australia, supplying around 80% of the electrical load in Australia. It serves a peak demand of ~35 GW (2010-11) [8] and energy consumption of ~190 TWh pa (2012-13) [9]. Due to the large distances involved, there are no electrical connections between the NEM and any other markets within Australia, or internationally.

The NEM is a gross pool, energy-only market, with a very high Market Price Cap (MPC) of $12,900/MWh. Retailers (often termed suppliers or load serving entities in other markets) are permitted, but not required to bid into this market. Almost all choose not to and hence AEMO bids in its forecast of non-scheduled demand into the market at the MPC. Compared with many international markets, there are relatively few restrictions placed on the offers of market generation participants In particular, they are permitted to offer generation at any price up to the MPC. Exercise of transient market power is viewed as an important aspect of NEM design to avoid the 'missing money' problem [10, 11, 5]. Security constrained market dispatch solves five minute wholesale prices for five market regions, corresponding to the boundaries of those States participating in the NEM.

The NEM is a single platform market, with only a single five minute (real-time) market. There is no day-ahead market; instead, market participants manage their own unit commitment, with the assistance of pre-dispatch forecasts provided by the Australian Energy Market Operator (AEMO). Market participants may re-offer their capacity at any time until immediately before the relevant five minute dispatch interval [12]. Notably, no physical bilateral contracts are permitted between market participants. There are associated frequency control ancillary services markets, and a range of derivative markets based on future spot prices, to facilitate risk management and investment.

III. Managing Resource Adequacy in the NEM

Resource adequacy in the NEM is based around an externally set Reliability Standard. At present this Reliability Standard is defined as 0.002% unserved energy per annum, measured over the long term. It is defined by the Reliability Panel, and is intended to broadly reflect the level of reliability valued by customers.

The Reliability Standard is implemented in the market via a number of price mechanisms, the most important of which is the Market Price Cap (MPC). The higher the MPC, the more revenue a new entrant can expect to make during periods of market scarcity (actual, or perhaps as a result of the exercise of market power). Thus, the attractiveness of investment in new capacity in the NEM is directly affected by the MPC, in combination with market expectations of how often extreme prices are likely to occur. For variable renewable generation, there is the additional complexity of the actual generation available at these times.

Still, with perfect foresight, the MPC could be 'tuned' to provide the precise level of investment incentives for new plant to be installed to exactly meet the Reliability Standard. Investment in further capacity beyond this point would decrease the incidence of scarcity (and therefore reduce the periods over which plant can capture the benefits of receiving the MPC), and investment in less capacity would provide an opportunity for a new entrant to receive sufficient revenue to make a return.

It can be argued that these NEM arrangements effectively provide a capacity market. However, it is a capacity market which only pays generators for the capacity that they actually provide at the precise times that this capacity is required. This differs from formal capacity market arrangements which often pay for capacity on an ongoing basis with less assurance that the capacity is actually required, or will actually be available at those times it is actually required.

Every four years the Reliability Panel conducts a comprehensive review of the Reliability Standard and Settings. Typically, as a part of this process, modelling is performed to determine what these price mechanisms should be set to in order to meet the Reliability Standard. To account for uncertainty, a very large number of Monte Carlo simulations are run, exploring different combinations of plant forced outages and other relevant market parameters. Generation is added to the market until the 0.002% unserved energy standard is just met. The price mechanisms (and most significantly the MPC) are then set such that the last generator dispatched (usually a peaking generator) makes a sufficient profit to make a return on their investment. Again, variable renewables may add considerable complexities to such calculations, as discussed in section X.

The MPC is under review at present [13]. If adjustment is deemed appropriate, this will take effect from 2016.

IV. Managing Price Volatility in the NEM

Due to the very high MPC in the NEM, market participants rely upon hedging mechanisms to manage risk.

Retailers in the NEM carefully procure a portfolio of derivative contracts to cover the majority of their anticipated customer load, or vertically integrate to supply generation with their own assets. In some cases these contracts can be similar in operation to a capacity market. In particular, there is a significant market for call options which provide the buyer with a fixed maximum price for some contracted volume over a contracted future period. For example, consider a cap contract with a \$300 strike price. Under this contract, a retailer agrees to make a fixed payment (\$/MW per contracted hour) to a generator. In exchange, the generator agrees to pay the difference between the strike price and the pool price, whenever the pool price exceeds the strike price. For example, if the pool price was \$1000/MWh, under the \$300 strike price contract the generator would pay \$700/MWh to the retailer. Thus, the retailer receives an effective market price cap of \$300/MWh on the contracted capacity. The generator receives a certain fixed revenue, supporting their fixed costs (similar to a capacity payment in a capacity market). Such fixed revenue also provides a basis for investment in new plant.

Importantly, decisions on the amount of capacity to be contracted are made by the retailer, who is best placed to understand the likely demand of their customers. The retailer is also strongly incentivized to contract for the correct capacity, ensuring limited exposure to extreme market prices, but also avoiding purchase of excess capacity.

Furthermore, the generator is strongly incentivized to ensure that their unit is available to the contracted amount when extreme prices occur. If a contracted unit experiences a forced outage, they will not earn the high revenue associated with this extreme price that will be required to compensate the retailer. This could be extremely expensive. This means that generators will carefully consider and manage the likely availability of their units during extreme pricing periods and contract accordingly (for example, they may contract only three out of four units, leaving one in reserve).

Thus, contracting tools of this nature can provide many of the benefits of a capacity market, but allow retention of the majority of decision making powers with market participants, who are best placed to manage the associated risks. With access to a liquid derivatives market, participants can contract to the level they want, in the manner they want, to manage their risk.

In theory, contracts of this nature drive investment. When a retailer anticipates a risk of exposure to extreme prices they will seek contracts with a generator. If there is insufficient capacity in the market, a developer could introduce a new entrant (supported by a long term agreement) to meet that demand.

V. Impacts of Renewables

Renewable technologies have a number of unique characteristics that will influence the operation of electricity markets. These include:

– ***Variability and uncertainty*** – Some renewable technologies (notably wind and solar photovoltaics) are variable and more uncertain than conventional generation technologies with storable primary energy resources. Their available generation will vary depending upon the availability of their underlying primary renewable resources.
– ***Non-synchronous*** – Some renewable technologies (such as wind and solar photovoltaics) are connected to the grid via power electronics, or non-synchronous generators, rather than via the synchronous generators used by conventional generating plant. This means that they will not contribute inertia to the system to assist in stabilizing system frequency (unless a synthetic response is added).
– ***Zero SRMC*** – Almost all renewable technologies (except biomass) have a zero or very low short run marginal cost (SRMC). They typically have no fuel costs and very low variable operating costs.

Variability, uncertainty and the non-synchronous nature of some renewables can be manageable in a 100% renewable power system by implementing a mix of technologies, including some renewable technologies that have a stored primary energy resource (such as geothermal, biomass, solar thermal with storage, and hydro). Furthermore, diverse geographical distributions of the variable resources can also assist in smoothing out their overall variability. The AEMO and UNSW 100% renewable energy studies explicitly sought to find the least cost mix of technologies and their locations across the NEM in order to achieve this.

However, since almost all renewable technologies have very low SRMCs, in order to operate a 100% renewable power system, it will be necessary to operate an electricity market almost entirely composed of zero SRMC generation. The market implications may be substantial.

Efficient energy-only wholesale markets should drive preference revealing bidding where generators offer the majority of their power at short run marginal cost (SRMC). Thus, in a competitive electricity market, the very low SRMC of renewables is likely to lead to an increasing proportion of low priced periods. This is already being observed in depressed wholesale electricity prices in a growing number of electricity industries including the NEM region of South Australia (which features a wind penetration approaching 30% by energy) [14].

This is not an entirely new situation, since the present NEM already includes very low SRMC generation. For example, the NEM's coal-fired generation typically has very low fuel and operating costs. Victorian brown coal generators are estimated to have an average SRMC less than $10/MWh (in the absence of carbon pricing). Some major generators, such as Hazelwood, Loy Yang A and Yallourn, have an estimated SRMC less than $3/MWh [15]. The majority of the cost of these generators is capital and fixed costs, meaning that their Long Run Marginal Cost (LRMC) is much greater than their SRMC. Thus, in many ways, the cost profile of coal-fired generation (in the absence of carbon pricing) is similar to that of renewable technologies, as illustrated in Table 1.

Table 1 - Comparison of Wind and Brown Coal Technology Cost Parameters in Australia

Generation type	SRMC ($/MWh)	Capital cost ($/kW)	LRMC ($/MWh)
Wind	0 - 12	2400 - 2700	80 - 100
Brown coal	3 - 10	3600 - 3900	50 - 60

Sources [15, 16]. Assumes no carbon pricing. Australian dollars are applied throughout. 1AUD ~ 0.7 Euros or 0.9 USD.

A potentially similar situation arises with nuclear power (although there is no nuclear power installed in Australia at present). Hydro power is another example, featuring both high capital and low operating costs (although the operating strategies of hydro generation is complicated by the energy limited nature of the resource).

In the present NEM, however, prices are inflated by the presence of a *range* of technologies with diversity in costs, operating to various degrees as load varies according to daily and seasonal patterns. For example, gas-fired generation typically has much higher fuel costs than coal-fired generation. Thus, investors in coal-fired generators rely upon periods where more expensive generators are operating and setting the price, allowing them to recoup fixed costs. The highest priced plant (peaking gas or distillate plant at present) also require operation during periods with prices above their SRMC to recoup fixed costs; this is allowed to occur in the NEM during periods of scarcity, when prices can reach the very high MPC.

As discussed, in a 100% renewable market there will be far more limited diversity in SRMC. This is likely to mean that market participants cannot reliably expect recovery of fixed costs during periods when more expensive units are operating and setting the market price. Instead, they will need to rely upon periods of scarcity, where a portfolio has market power and can escalate prices to the MPC. Markets with a significant penetration of biomass could be a possible exception, although this is unlikely to apply in the NEM due to resource constraints.

Based upon spot market revenues, generators in the present NEM already recoup a significant proportion of fixed costs during extreme pricing periods. For the highest operating cost generators such as Open Cycle Gas Turbines, these may be the only times at which they can do so. On average, one quarter of aggregate generator annual revenues have been earned during periods with prices exceeding $300/MWh, although these periods typically only occur around 1% of the time. However, substantial inter-annual variability is evident; historically the proportion typically ranges from 12% to 36% of revenues earned during these high priced periods [17].

Renewable generators exhibit an even more extreme profile. Based upon spot market revenues alone, on the highest 20 revenue days in the year wind generators in the NEM market might expect to earn 15-55% of annual revenues, and solar plants might expect to receive 15-70% of annual revenues [18].

Generators are not typically exposed to this volatility. Most will contract for the majority of their capacity, providing a smoother and more certain revenue stream. However, the details of these contracts could be expected to be strongly dependent upon the market expectation of extreme priced periods. Variable renewable generators may face additional challenges in entering such contracts given their volume risk and non-firm capacity.

With a move to a high renewable market, and a corresponding reduction in median prices, the proportion of revenue earned during extreme pricing events would need to increase significantly. In the most extreme case with very low SRMCs for all the renewable technologies (for example, generation mixes that don't feature biomass) this proportion of revenue could be expected to approach 100%. Increasing this revenue sufficiently to maintain resource adequacy could then be achieved in two ways:

1. An increase in the incidence of extreme pricing periods, or
2. An increase in the Market Price Cap (MPC).

An increase in the incidence of extreme pricing periods whilst maintaining the Reliability Standard could be driven by a range of factors. This could include a change in the shape of the net demand profile, such that the amount of Unserved Energy (USE) is maintained at the same level, but more periods of constrained supply and hence extreme prices occur. This could be influenced by an increase in the levels of variable generation, if it were correlated with demand in some manner. Alternatively, a higher degree of market concentration (allowing a single portfolio to set prices more frequently) could also facilitate more extreme price events.

Increasing market concentration threatens market competition, and is therefore unlikely to be desirable. A change in the net demand (demand minus variable generation) shape as described above may occur, but this is likely to be difficult to accomplish in a deliberate and managed manner. Therefore, the regulatory bodies that manage the market appear to be left with the other option from the list above: increase the MPC. This is the primary 'lever' available to adjust investment incentives.

Including renewable technologies in reliability assessments has been extensively considered over the past decade [19]. Thus, with some adjustments the usual reliability modelling used for setting the MPC (described in section III) could potentially be able to adequately capture the impact of increasing renewable generation, and adjust the MPC accordingly. Modelling of this nature is underway at present [13]. This modelling process will not be without challenges in future, as discussed in section X.

VI. CALCULATING THE REQUIRED INCREASE IN THE MPC

The amount by which the MPC may need to increase will depend upon a range of factors. As discussed above, the shape of the net demand curve and the degree of market concentration both affect the frequency of extreme pricing events, which in turn dictates the MPC required to ensure revenue sufficiency for the required amount of capacity.

With the electricity sector embarking on a period of rapid and dramatic transition, both of these factors are highly uncertain at present. This makes it difficult to make any predictions about how much the MPC might need to increase to support a high renewable penetration market.

Nevertheless, an indicative estimate of the degree to which the MPC might need to increase is of value in understanding how such an approach might function. Thus, we proceed with analysis based upon historical NEM data, implicitly assuming a similar net demand profile and degree of market concentration to the present.

A. Methodology

Trading interval (30min) regional pricing and demand data was procured from the Australian Energy Market Operator [17].

An "adjusted" price profile was calculated as follows. The price was set to zero in every region and every half hour where the price was below \$300/MWh. These periods were considered 'competitive', and therefore likely to experience a decrease of prices to close to zero with increased renewable penetration. The prices in the remaining periods were multiplied by a "scaling factor", effectively 'stretching' the price profile. The scaling factor was adjusted to match the aggregate total revenue earned over the year to the desired level. Two scenarios were considered:

- ***Historical*** – The scaling factor was adjusted so that aggregate total revenues earned in the 'adjusted' price profile over the year matched those actually earned historically in that year.
- ***100% renewables*** – The scaling factor was adjusted so that the aggregate total revenues earned in the 'adjusted' price profile over the year were sufficient to cover the aggregate total cost of a 100% renewable power system.

We make the assumption that the 'scaling factor' calculated via this process is representative of the factor by which the MPC might need to be increased from present. Prices at levels between \$300/MWh and the MPC are caused by a range of factors, including averaging of five minute dispatch interval prices into a 30 minute trading interval, where some five minute prices may be at the MPC and others may not (perhaps due to transient market power). Effects of this nature might be expected to scale somewhat linearly with an increase in the MPC.

The costs of a 100% renewable power system were sourced from detailed modelling conducted by AEMO. Their analysis finds that to cover the capital and operating costs of generation, storage and network connections for a 100% renewable power system in the NEM would cost in the range of \$111/MWh (2030, low cost scenario) to \$133/MWh (2050, high cost scenario) [1]. These are volume weighted average costs.

B. Selection of an appropriate historical year

In conducting this analysis it is important to select an appropriate historical year, with a price and demand profile that could be considered 'typical' and representative of a market with the desired level of reliability.

The NEM Reliability Standard is defined as 0.002% unserved energy (USE) per annum, measured *over the long term*, which is typically assumed to mean at least a ten year period [20]. The standard is indifferent to whether this occurs in small events every year, or in a large event in a single year during a ten year period.

In the absence of a large data set covering many years, we aim to select an historical year in which USE levels were close to the Reliability Standard. All else being equal, it could be expected that the duration and frequency of extreme pricing events in that year would be representative of a longer term sample meeting the same Reliability Standard.

Since 2005, USE related to a deemed reliability event has only occurred during the extreme heat wave in 2009 [21, 20]. USE experienced in other years has been deemed to have related to system security (not reliability), and is therefore not included within resource adequacy assessments [21]. In 2009, 2301 MWh of reliability-related USE occurred, equivalent to 0.0011% of aggregate NEM demand in that year.

The USE level on average across the NEM is far lower than that permissible under the Reliability Standard. Over the period 2005 to 2010, the NEM has achieved 0.0002% USE on average per year, ten times lower than the standard allows. Even in 2009, aggregate USE was around half the allowable standard. This suggests that the amount of installed capacity in the NEM may be in excess of the requirement to meet the Reliability Standard. Exceeding the standard is not necessarily problematic, although achieving reliability does come at a cost. Thus, a system could be considered 'too reliable', given the preferences of consumers. However, given that USE can be driven by large, rare events, this six year sample is not statistically adequate to confirm such a conclusion.

The reliability related USE that occurred in 2009 was limited to the Victoria and South Australia regions. Assessed on a regional basis, in this single year, USE levels reached 0.004% and 0.003% in those regions respectively [20]. These levels exceed the 0.002% requirement, but given that the Reliability Standard is assessed over multiple years, these regions remain compliant with the standard.

This data suggests that the year 2009 is the most appropriate year for this analysis. 2009 has the closest level of USE to the Reliability Standard, and therefore is most likely to have a representative price and demand profile for a market that delivers the desired level of resource adequacy. Importantly, however, even in 2009 the USE level is around half that defined in the Reliability Standard. This suggests that an MPC adjustment calculated based upon this year is likely to be an overestimate (all else being equal, a lower MPC may suffice to ensure resource adequacy sufficient to meet the Reliability Standard).

C. Results

Table 2 lists the scaling factors and corresponding MPC levels calculated to be necessary to achieve aggregate revenue sufficiency in each of the cases considered. In 2009, the MPC was $10,000. This analysis finds that aggregate revenues in 2009 could be maintained in the event that all prices below $300/MWh were reduced to zero, if higher priced periods were scaled up by a factor of 3. This would correspond to increasing the MPC by a factor of 3 to around $30,000/MWh.

To cover the costs of a 100% renewable power system a further increase in the MPC is required, to recover additional costs of the more expensive generation in addition to compensating for the reduction of median prices to close to zero. To recover an average system cost of $111 - $133/MWh (as calculated by AEMO) prices above $300/MWh need to be scaled up by a factor of 6 to 8 (with the range corresponding to the low and high estimates by AEMO). This suggests an increase of the MPC to around $60,000 - $80,000 /MWh. This is a significant increase from the present, and would need to be implemented careful consideration of the cautionary factors discussed in section VIII.

TABLE 2 – PROJECTED MARKET PRICE CAP LEVELS REQUIRED

	Scaling Factor	**MPC ($/MWh)**
Present (2013)	-	$12,900
Level in 2009 (reference year)	1	$10,000
Maintaining historical aggregate revenues	3	$30,000
Sufficient aggregate revenues to support 100% renewables	6 - 8	$60,000 - $80,000

D. Limitations

The historical analysis approach applied here has many limitations, and cannot replace detailed reliability modelling. It is only intended to capture the order of magnitude of change that may be required.

By using an historical price profile this analysis implicitly assumes a market with similar characteristics to present. However, a 100% renewable market could be expected to be dramatically different in many ways. For example, AEMO's modelling of 100% renewable scenarios includes significant quantities of solar generation [1]. This is likely to greatly change the manner in which scarcity events occur, such that they are no longer driven by hot summer peak demands, but rather by extended periods of low solar and wind generation coinciding with high demand. Cold and still winter evenings present obvious challenges [22, 23]. These effects are not captured by this analysis.

This approach does not consider the distribution of revenues between market participants; only the aggregate level of revenues are calculated. Particularly in the case of variable renewables, if they are infrequently operating during extreme price events, they may not earn sufficient revenue to recover their costs. However, this is a strong indication that this generator is providing minimal value to the system (since they are primarily operating when energy is 'free'), and is not effectively contributing to system reliability. Nevertheless, distributional effects should be considered in future work.

VII. VALUE OF CUSTOMER RELIABILITY

At present in the NEM, the value of customer reliability is not explicitly considered in the setting of the MPC. The following process is applied:

1. Determine the desired Reliability Standard (amount of USE), having regards to perceived customer preferences
2. Conduct modelling to determine the appropriate MPC to incentivise sufficient investment to target this level of USE
3. Allow the resulting cost of reliability to be passed on to consumers

The only point in this process at which the value of customer reliability is considered is in the setting of the Reliability Standard. Assumptions about the cost of achieving a certain reliability standard are implicitly included. This suggests that if the cost of achieving a certain Reliability Standard changes significantly, the Reliability Standard should be revised.

It has also been noted that less than 1.2% of interruptions to end-user supply in the NEM are related to generation adequacy [24], with the vast majority relating to security events and network outages. This suggests that the Reliability Standard could be relaxed with a minimal impact upon consumers. This would allow a lower MPC to be applied, all else being equal.

Proponents of energy-only market models have proposed that the MPC should be set directly by the Value of Lost Load (VoLL) [4]. Rather than defining a somewhat arbitrary level of reliability that must be achieved, customers would instead provide information about their willingness to pay for reliability. The VoLL would then become the MPC, in turn determining investment incentives, and therefore the amount of unserved energy that should optimally occur (based upon customer preferences).

Thus, the NEM could reasonably consider inverting the present process as follows:

1. Determine the value of customer reliability ($/MWh)
2. Apply this as the MPC
3. Allow the resulting USE levels to occur (since they would be reflective of the value of customer reliability)

This approach would allow the market to respond with the appropriate level of reliability, as desired by customers. This could be particularly important as a transition to new technologies (such as renewables) occurs. As pointed out by Cramton and colleagues [7], the introduction of renewable technologies does not change the value of customer reliability, and therefore, in this framework, introducing renewables would not influence the MPC. However, the level of USE may change, reflecting the different cost of achieving reliability with these new technologies.

There have been a range of studies attempting to determine the value that customers in the NEM place upon reliability [25, 26, 27, 28]. This measure is used primarily for assessing the cost/benefit profile of network investment options, but the assessment is also applicable to resource adequacy reliability. Approaches typically involve quantitative customer surveys to gather data on the cost impacts of unplanned electricity supply interruptions.

Results from a recent (2012) assessment of customers in the New South Wales NEM region are listed in Table 3 [28]. The average value of customer reliability is estimated at close to $95,000/MWh. The significant mismatch between the present MPC ($12,900/MWh) and the value of customer reliability indicates that the Reliability Standard is too relaxed at present to appropriately represent the true value of customer reliability.

The estimated value of customer reliability is also significantly higher than the MPC values projected to be required for system adequacy in a high renewable system. This suggests that the projected MPC values may remain within sensible parameters of the system.

TABLE 3 – ESTIMATED VALUE OF CUSTOMER RELIABILITY IN NSW

	Value of Customer Reliability ($/MWh)
Residential	20,710
Small business	413,120
Large business	53,300
Average (volume weighted)	94,990

Source: [28]

These results suggest that certain groups (such as residential customers) value reliability at a substantially lower level than average. This suggests there could be an opportunity for demand aggregators: aggregating customers to directly participate in the wholesale market, with customers receiving lower electricity prices in exchange for a lower level of reliability. This potential for individual customer choice over their desired level of reliability has been cited as one of the key advantages of energy-only market designs [29].

It has been long recognised that issues related to resource adequacy could be eliminated by sufficiently increasing demand elasticity [7]. Without an MPC, inelastic consumers could be exposed to unreasonably high prices that would not be representative of their desired reliability level (and associated costs).

However, if there were comprehensive demand side participation, it would not be necessary to determine an aggregate reliability standard. Each customer could elect to remove load from the system in response to price, reflecting their individual value of reliability.

Like many markets, the NEM has recognized the many benefits of eliciting an increased demand response, and is working to remove the barriers to this [30]. As individual customers engage more of their load in active demand side participation, they can choose the desired reliability level (and characteristics) that suit their preferences. The aggregate reliability standard implied by the MPC can then gradually apply to a diminishing proportion of the system. Eventually, with very comprehensive demand side participation, it may be possible to remove the need to apply a regulated MPC.

VIII. BARRIERS TO INCREASING THE MPC

There are a range of issues to carefully consider before the MPC is increased. Firstly, with an increase in the MPC, the risks to market participants of operating in the NEM would increase, particularly for retailers. With a deep and liquid derivatives market, suitable hedging instruments are likely to be available, but the premiums on these instruments are likely to increase. At present, swap premiums in the NEM are consistently around $2/MWh above spot prices [24], and $300 cap contracts are trading at $9-$13/MW in Quarter 1, and at $2 - $7 in other Quarters [31] (varying by region). These prices would be likely to increase if the MPC increased substantially. This cost would ultimately be borne by consumers through retailer premiums.

Secondly, AEMO is exposed to the risk of market participants defaulting, and this risk is managed via prudential requirements in the National Electricity Rules. The requirements are intended to cover AEMO's worst case exposure, taking into account the potential for spot price volatility in the NEM. With an increase in market volatility and an increase in the MPC, this worst case exposure would be likely to increase, which would then require an increase in the prudential obligations for market participants. This has the potential to raise barriers to entry, particularly for smaller participants [32]. This is not ideal in a period where a rapid transition to new technologies is required.

Thirdly, with an increase in the MPC, the potential for larger inter-regional price differences increases. Given that Inter-Regional Settlement Residues do not offer a perfect hedge, this would increase the risks of inter-regional contracting. This could ultimately interfere with locational signals, driving new entrants to locate in the same region as their intended load, despite potentially more economically efficient locations being available [32].

IX. Contracts markets

A liquid and well-functioning derivative contracts market is already essential for NEM operation. Given that market participants must operate in an environment that allows market prices to reach \$12,900/MWh and as low as -\$1000/MWh, it is imperative that effective hedging tools are available to manage price risk. The contracts market provides this.

NEM participants can choose to contract over the counter (OTC) (bilaterally or via brokers), or through the Sydney Futures Exchange (SFE) [33]. Bilateral agreements may be preferred in some cases since they can be tailored to hedge unique retail load profiles or plant maintenance intervals [34]. However, trades on the SFE have other benefits (such as greater anonymity, lower counterparty risk and credit benefits), and are increasing over time [34]. Since 2008-09, trades on the SFE have exceeded half the traded volume [35].

The NEM has a relatively liquid contracts market (by international standards for electricity markets). Traded volumes easily exceed NEM demand; for example, in 2011-12, traded volume represented 231.2% of underlying NEM system demand [35].

If the MPC is increased, the potential risks of operating in the market will increase, and the contracts market will become even more important to allow generators and retailers to hedge successfully. Analysis of SFE trades suggests that the now relatively mature market for hedging instruments should be able to respond quickly to any changes in market participants' hedging needs relating to an increase in the MPC [32]. However, this analysis related to a smaller increase in the MPC than proposed here.

Vertical integration has been steadily increasing [33], with market participants appearing to prefer a 'physical hedge'. So called "gentailers" operate generation to supply their own customer loads, removing the need to contract externally. If vertical integration increases further, supply of hedging products may be reduced. However, it has also been argued that physical positions cannot fully eliminate volume risk, and further that they provide more ability to quote two way prices and hence become more active in the market and improve liquidity [34]. Some analysis suggests that the trends towards vertical integration may be offset by the emergence of new asset owners, an increase in the number of active financial intermediaries, and the general growth in maturity of the market over time [34].

Three major gentailers increasingly dominate the retail market [33] suggesting the potential for significant market power in the contracts market. This may reduce access to hedging mechanisms for smaller market participants.

A well-functioning derivatives market is essential to support the reliable operation of the NEM. In light of this, it may be pertinent to increase the level of monitoring, particularly if the MPC were to be increased.

X. Challenges in Calculating the MPC

Calculating the MPC is already a very challenging process. Detailed reliability modelling, based upon large numbers of Monte Carlo simulations are typically required. The modelling will require a view as to the range of possible scenarios the future market may experience. Typically assumptions are based upon an historical assessment of the relevant factors, and apply trends forwards in time. However, electricity markets globally are in a period of sustained and rapid transition, with associated significant uncertainty.

Determining the appropriate shape of the net demand curve during scarcity periods is already challenging, since it relies upon sampling of a very small historical sample (given that scarcity periods by nature occur infrequently). The challenge will be exacerbated by the entry of a range of disruptive technologies such as wind and solar generation, demand side participation, electric vehicles and embedded generation. Any of these technologies may dramatically change the characteristics of the net demand curve. Furthermore, the degree of market concentration could be dramatically reduced by the rapid transformation to new technologies (particularly embedded technologies), or may remain similar to present levels if centralized power models remain common.

These factors are likely to make it increasingly challenging to perform the necessary calculations for determining the appropriate MPC.

XI. Conclusions

It is widely agreed that the NEM appears to have functioned effectively to date. Indeed, the NEM is often held up as a "successful model" for other markets to aspire to [36]. From the inception of the NEM in 1999 to June 2012, new investment has added over 13GW of registered generation capacity – around 1GW per year in a market with a peak demand of ~35 GW [33]. Investment is influenced by many factors, including Government support of new entrants through schemes such as the Queensland Gas Scheme and the Renewable Energy Target. However, this degree of investment at least suggests that the energy-only market design is not deterring investment interest.

The current NEM design promotes investment via a very high Market Price Cap (MPC). Generators are permitted to offer at the MPC and rebid at very short notice. The potential for extremely high price periods provides considerable motivation for large electricity customers and retailers to sign long-term derivative contracts with generation developers. However, large scale deployment of low SRMC and potentially variable renewables represents a different scale of challenge.

Preliminary analysis suggests that existing mechanisms may have the potential to operate effectively in a 100% renewables scenario, but success will rely upon several critical factors, including further increase of the already very high Market Price Cap, and a liquid and well-functioning contracts market, to enable market participants to successfully manage significant risk.

Therefore, at this stage it appears that the introduction of a capacity market in the NEM may be a retrograde step, shifting decision making and risk management from market participants to a central authority [4]. Energy-only markets also have the advantages of relative technology neutrality, while capacity market mechanisms may increase the challenge of integrating variable renewable technologies by raising questions about their appropriate capacity value [19]. There have been suggestions of a convergence of market designs to address this issue, with capacity markets moving towards a technology-neutral mechanism that could involve auctioning of long term contracts for capacity [23].

Instead of dramatic market reform, an approach of careful monitoring, with a particular focus on the contracts market, appears appropriate at this stage.

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