snowy hydro Limited
renewable energy

25th May 2017

Mr John Pierce
Chairman
Australian Energy Market Commission
PO Box A2449
Sydney South NSW 1235

Reference Code: ERC0201
Submission by email at: aemc.gov.au

Dear John

Rule Change Proposal - Five Minute Settlement,
Directions Paper - Marsden Jacob Associates Critique

Snowy Hydro Limited is a generator and retailer of energy in the National Electricity Market (NEM) and a leading provider of risk management financial hedge contracts. We are an integrated energy company with more than 5500 MWs of peaking generating capacity including the iconic 4100MW Snowy Mountains Hydro-electric Scheme. We are one of Australia's largest renewable generators, the third largest generator by capacity and the fourth largest retailer in the NEM through our award-winning retail energy companies - Red Energy and Lumo Energy.

The attached report presents the findings of an independent study undertaken by Marsden Jacob Associates (Marsden Jacob) on the economic and electricity consumer impacts of moving to 5 minute energy settlement in the National Electricity Market (NEM).

Marsden Jacob concludes that based on their review of the available evidence, it appears that there is material risk that 5 minute settlement will increase costs to consumers. In particular a move to 5 minute pricing would:

- Significantly impact the relationship between the spot and contract markets, and substantially reduce the level of Cap contracts that could be provided;
- Result in changed and substantially more costly generation operation by requiring more generators to be operating, including OCGT plant running on gas;
- Result in higher FCAS costs resulting from an increase in demand for FCAS services due to increased intra-5 minute demand uncertainty and reduced supply of such services;
- Require an increase in the Maximum Price Cap;
- Increased risk across the market; and
- Require the installation of battery technology before it is economic to do so. Based on projections of NEM prices in energy and ancillary services, and battery cost

outlooks, the study found that batteries were not likely to be economic until post 2030. The study also found that in the absence of network benefits, which are uncertain due to the limited storage of batteries, the economics of batteries may be further delayed.

Marsden Jacob assessed the likely impacts of 5 minute settlement on both revenues and/or costs in various electricity markets (e.g. spot, ancillary services and the market for Cap contracts), as well as the level of liquidity in the Caps market. The potential cost and revenue impacts are significant as shown in the table below.

Component	**Change**
Caps Offered	Reduction of at least 4,000 MW
Cap Premiums	Increase of at least $130 M per annum
Out of Merit Dispatch Costs	Increase of $60 M per annum
Frequency Control Ancillary Service Costs	Increase of $15M to $30M per annum

Marsden Jacob also noted the implementation costs of 5 minute settlement has been calculated from Russ Skelton and Associates to be in the order of $250 million. These impacts and costs of 5 minute settlement are significant and Marsden Jacob concludes that there is a material risk that this rule change would result in substantial price increases to consumers.

Snowy Hydro notes that Marsden Jacob's analysis on the quantity reduction in Cap contracts and increased in premiums for Cap contracts has derived comparable values to the analysis conducted by Snowy Hydro in its submission dated 18th May 2017. Snowy Hydro used a different methodology of estimating the reduction in Cap volumes from analysing NEM regional bidstacks for the Trading Period 12:30 on Monday 10th April 2017.

The Marden Jacob report of 5 minute settlement is submitted to this Directions Paper consultation. Snowy Hydro appreciates the opportunity to participate in this consultation process. For any enquiries on the Marsden Jacob Associates independent critique, I can be contacted on kevin.ly@snowyhydro.com.au.

Yours sincerely

Kevin Ly
Head of Wholesale Regulation

REPORT 25 MAY 2017

Impact of 5-Minute Energy Settlement

Report prepared for Snowy Hydro

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Executive summary

The Australian Energy Market Commission (AEMC) is seeking to determine if the introduction of 5 minute electricity settlement will materially improve the efficiency of the electricity market. This paper has been prepared for Snowy Hydro in relation to the ongoing discussion of the proposed rule change (reference ERC0201).

While the concept of 5 minute energy settlement (*"5 minute pricing"*) is conceptually straightforward, the interaction with other market functions and associated consequences are complex and substantial.

ES1 Conclusions

Based on our review of the available evidence, it appears that there is material risk that 5 minute settlement will increase costs to consumers. In particular a move to 5 minute pricing would:

- Significantly impact the relationship between the spot and contract markets, and substantially reduce the level of cap contracts that could be provided;
- Result in changed and substantially more costly generation operation by requiring more generators to be operating, including OCGT plant running on gas;
- Higher FCAS costs resulting from an increase in demand for FCAS services due to increased intra-5 minute demand uncertainty and reduced supply of such services;
- Require an increase in the MPC;
- Increased risk across the market; and
- Require the installation of battery technology before it is economic to do so.

The following table provides a summary of the likely impacts of 5 minute settlement on both revenues and/or costs in various electricity markets (e.g. spot, ancillary services and the market for caps), as well as the level of liquidity in the caps market. The potential cost and revenue impacts are significant.

ES Table 1: Estimates of the Impact of 5 minute settlement

Component	Change	Source
Implementation Costs (e.g. IT systems, re-contracting etc.)	Increase of $250 M	Russ Skelton and Associates, *5 Minute Settlement, Assessing the Impacts*, March 2017, p.23
Caps Offered	Reduction of at least 4,000 MW	Marsden Jacob. Section 6.1.1 of this report
Cap Premiums	Increase of at least $130 M per annum	Marsden Jacob. Section 7.2.1 of this report
Out of Merit Dispatch Costs	Increase of $60 M per annum	Marsden Jacob. Section 7.2.1 of this report
Frequency Control Ancillary Service Costs	Increase of $15M to $30M per annum	Marsden Jacob. Section 7.3 of this report

Based on Marsden Jacob's many years of both theoretical and *"in market"* experience, and analysis of the available information, our professional opinion is that there is a material risk that this rule change would result in substantial price increases to consumers.

The overriding conclusion of this report is that any move in this direction must give proper consideration and appreciation of the follow-on consequences.

To properly assess the impact before any decision is taken on this rule change, it is essential that both economic (cost-benefit analysis) and a price impact assessment is undertaken both in aggregate and from a distributional perspective to check whether the proposed change is improving outcomes for final electricity customers.

ES2 Overview

The introduction of 5 minute pricing would interact with the following NEM functions;

- Energy market price signals (the primary reason for the suggested change);
- The relationship of capacity needed to provide a given amount of energy in a dispatch interval;
- The risk of providing derivative contracts, particularly cap contracts;
- Incentives for non-scheduled generators and demands (another stated reason for the suggested change);
- The quantum of frequency control ancillary services (FCAS) that may need to be procured and the available suppliers of these services; and
- Power system reliability in terms of the settings required and plant response.

The AEMC has indicated that investment in new technologies, such as battery storage, will enable market participants to respond to 5 minute price signals in the future (hence the need for a 5 year transition period as outlined by the AEMC).

However without an affordable and cost efficient technological response, 5 minute settlement would significantly impact the functioning of the market (as outlined above) in a manner that substantially lowers economic efficiency (as measured under the National Electricity Objective), with a consequent increase in prices paid by customers.

ES3 Assessment of Issues

Energy market price signals

A review of past spot prices shows that the majority of 5 minute dispatch interval price "spikes" have been single (or isolated) 5 minute spikes.[1] Reasons for this include peaking plant response which will generally miss the first 5 minute dispatch interval price spike and capture the second 5 minute dispatch interval price spike (if there is one). The response of peaking plant often results in a potential price spike not occurring in later 5 minute periods of a 30 minute trading interval.

Derivative contract (Cap) Risk

Derivative contracts are a basic component of electricity spot markets. It has been understood for many years that the efficient operation of the spot market requires a proper functioning

1 Russ Skelton & Associates, *5-Minute Settlement, Assessing the Impacts*, Report prepared for the Australian Energy Council, March 2017.

contract market. Key issues are contract liquidity, price transparency and managing market risk (e.g. spot market price spikes).

The bulk of sold derivative contracts have risk contained through coverage by physical peaking plant. Due to the technical characteristics of peaking plant (e.g. hydro, Open Cycle Gas Turbines (OCGT), etc.), the ability for this plant to defend or manage price risk in five minute intervals will decrease for most, if not all peaking generators in the NEM. We also note that a consideration in the level of the Market Price Cap (MPC) is sold derivative contract risk.

Time to start and generate

The physical coverage of 5-minute price spikes comes from generation already operating (which includes peaking plant) and peaking plant not operating. The analysis in this report reviewed the response rate of such plant and showed that plant already operating (at minimum generation levels or more) could generally respond as required, but that peaking plant not operating could not start and ramp in time to commence supply in the first 5 minute dispatch period. This is very different under 30 minute prices where non-operating peaking plant could substantially capture the first 30 minute period.

The consequences of non-operating plant being unsuitable to capture the first 5 minute price spike, in a market dominated by single 5 minute price events, is that they become unsuitable to manage sold cap contract risk.

Capacity to cover 5 minute energy

The relationship between capacity (MW) required to provide a particular amount of energy (MWh) is different over a 5 minute period compared to a 30 minute period. Over a 5-minute period a generator commencing from zero output is required to linearly ramp to its target level. This implies that to supply an average of 1 MW in a 5 minute period a generator needs to have 2 MW of capacity. Over a 30 minute period a peaking generator will reach full capacity in (say) 10 minutes with the result the plant will be operating at maximum capacity for two thirds of the 30 minute trading interval (for 4 five minute dispatch intervals).

This means a scheduled plant needs more capacity to provide an average capacity level in a 5 minute period as compared to a 30 minute period. A very fast response generator, such as a battery, could overcome this by instantaneously increasing output to the required capacity level (almost a 1-to-1 relationship between capacity and energy delivered). As a consequence, of the almost immediate response by battery technologies (and more rapid response of other fast start plant, such as aero-derivatives), an increase in the amount of lower regulation services (and potentially other lower FCAS services) will be required to absorb the excess energy supply.

Cap Contract Reduction

Given the inability of existing peaking plant to respond to 5 minute prices from cold start, there will be a vast reduction in the level of cap contracts that can be supported by currently registered generation. In fact, existing plant may not be able to provide any cap contracts, unless the operating regime for the plant is altered (e.g. operate at minimum generation).

However a very conservative estimate of the reduction in cap contracts, is to ignore the energy/capacity issues raised above, and base it on the amount of peaking plant typically not operating at times when price spikes may occur (leaving aside that history has shown this can be at any time).

The estimated requirement to cover load flex (difference between maximum peak demand and average peak demand) in the mainland NEM is currently over 13,000 MW, with approximately 8,500 MW of peaking plant needed to cover this load and associated price volatility. It is estimated that due to the technical capability of peaking plant, the amount of caps available from existing providers under a 5-minute settlement market would reduce from the present situation by at least of 4,000 MW and most likely substantially higher than this. This is well in excess of the 625 MW amount suggested by Energy Edge (on behalf of the AEMC), which noted that they had only considered externally transacted cap products rather than the total market (accounting for vertical integration).

This would mean that without alternative means of covering cap contracts, the suppliers of cap contracts would need to keep plant operating, including peaking plant, than would have otherwise been the case. With more high cost gas plant operating under 5 minute dispatch, overall generation costs are likely to rise, with increased gas use further limiting the availability of gas for other users (e.g. domestic and industrial use).

Non-scheduled generators and demands

Non-scheduled generators and demands have the advantage of monitoring spot prices and reacting knowing that their actions will not impact spot price. It is well recognised that this results in increased 5 minute demand forecast error, inefficient use of demand side resources and generation facilities, and skewed spot price signals.

Five minute pricing would increase this *"turbulence"* by having non-scheduled entities react between 5 minute price periods.

Ancillary service

While 5 minute energy settlement periods do not involve intra-5-minute operations, there would nevertheless be a substantial impact to the frequency control ancillary service (FCAS) markets. This would arise for two reasons:

- Increased uncertainty and error in the 5 minute demand forecasts and less incentives to linearly ramp within a 5 minute period; and
- Reduced generator capacity that is available to undertake FCAS duties due to the need to be reserved for energy market response.

The consequences of this would result in additional plant being required, which would reduce the efficiency of both the energy market and FCAS operations.

Power System Reliability

The changed price signals would result in the 0.002% unserved energy criteria having a different distribution with peaking plant, necessary for reliability, receiving a lower revenue due to lower energy contributions at high price / low reserve times.

While the dynamics of this are complex and would need to be considered, it is likely that the MPC would need to be increased. This in turn would further increase the risk of providing sold cap contracts.

ES4 New technology

The review examined the dynamics of batteries, the services they could provide, their costs – current and projected, and their economics into the future.

The study found that battery technologies have the potential to provide a variety of services that include demand smoothing (through energy arbitrage) and FCAS (regulation and contingency). The study also found that their capability to provide network services (as well as system restart ancillary services) is very unclear due to their limited storage and inability to provide this and other services.

Based on projections of NEM prices in energy and ancillary services, and battery cost outlooks, the study found that for batteries were not likely to be economic until post 2030. The study also found that in the absence of network benefits, which are uncertain due to the limited storage of batteries, the economics of batteries may be further delayed.

1. Introduction

This report presents the findings of an independent study undertaken by Marsden Jacob Associates (Marsden Jacob) on the economic and electricity consumer impacts of moving to 5 minute financial energy settlement in the National Electricity Market (NEM).

1.1 Background

The Australian Energy Market Commission (AEMC) is reviewing a rule change proposal from Sun Metals that seeks to align the dispatch and settlement intervals in the wholesale electricity market.

Sun Metals proposed that the time interval for financial settlement in the wholesale electricity market be reduced from 30 minutes to five minutes. The proposal involves:

- Compulsory five minute settlement for generators, scheduled loads and market interconnectors; and
- A choice of either a five or 30 minute settlement interval for demand side participants, including retailers and large consumers.

As part of the process the AEMC published a directions paper on 11 April 2017 on this matter.[2] In the directions paper, the AEMC indicated they had formed a preliminary view in favour of the rule change, although they acknowledge the significant market disruption and costs that could be associated with such a change (e.g. meter costs, reduced supply of caps in the market, trading systems etc.).

The directions paper noted key benefits and costs of 5 minute settlement would include:

Benefits

- A market where dispatch and settlement cycles are aligned and price provides signals and incentives for supply to be responsive to demand, should drive more efficient wholesale market outcomes, especially given the increased penetration of intermittent plant in the NEM (in front of and behind the meter);
- Decreased incentives for disorderly bidding (such as high prices in the initial periods of a 30 minute interval followed by low or negative prices later in the interval). A rule change (*"Good faith bidding"*) was introduced to tighten rebidding rules and reduce disorderly bidding associated with price spiking behaviour that had been observed in later 5 minute dispatch intervals of a 30 minute settlement interval. Since the implementation of this new rebidding rule on and from July 2016, there has been significantly reduced incidences of price spikes in later dispatch intervals;
- By rewarding those technologies that can respond to a five minute price signals, would incentivise the development of flexible technologies that are now available to respond to high prices in 5 minute intervals, in particular battery storage and aero-derivative generation technologies.

[2] AEMC (2017) *Five Minute Settlement*, directions paper, 11 April 2017, Sydney.

Costs

The costs of 5 minute settlement would include:

- Required investments in IT systems (by AEMO and market participants) and metering infrastructure);
- Required changes in financial contracts to support 5 minute settlement;
- Increased financial risks for existing fast start plant and other providers of cap contracts, and a consequential reduction /increased cost in the supply of cap contracts; and
- Possible required changes to other market settings to ensure the reliability criteria is maintained (e.g. increase in the Market Price Cap).

1.2 Framework for Assessing the Rule Change

Fundamentally the economics of the NEM is reflected in the assets developed and how they are used to supply electricity. Economic efficiency is achieved when the following occurs:

- Productive efficiency - when costs associated with system operation are minimised in the short run;
- Allocative efficiency - when spot prices reflect underlying demand and supply conditions and provide incentives for participants to change behaviour (e.g. reduce consumption or increase generation);
- Dynamic efficiency - when new investment and innovation in new generation and other technologies (e.g. batteries) is both timely and minimises long run costs.

This report highlights the likely costs and additional risks that will be incurred by generators and market participants that result from implementation of 5 minute settlement. It is likely that any increased costs will be passed through to final retail customers.

The Commission's assessment of the rule change needs to consider whether the proposed rule change promotes the National Electricity Objective (NEO).

From the perspectives of the NEO it appears that the proposed reform is not intended to fundamentally change quality, safety, reliability and/or security of supply of electricity to consumers. The reform appears to be more about providing more refined market signals to those technologies that can respond more rapidly to price signals which would change generation operation and the future generation mix (in favour of very fast start plant).

The changed plant operation and future generation mix in response to 5 minute settlement will change costs and prices. The key issue from a consumer perspective appears to one of *"price"*, with lower prices leading to welfare gain for consumers and higher prices leading to welfare loss for consumers.

Our assessment of the impact of the proposed rule change of final electricity customers is provided in Section 7.4.

1.3 Terms of Reference

Marsden Jacob was engaged by Snowy Hydro to prepare this report on the impact of a move to 5 minute energy market settlements in the NEM.

The analysis was to review material published by the AEMC and to undertake are own analysis of a number of the key issues identified. This report does however not consider the considerable costs also involved for participants in relation to metering, settlements, pricing, system changes, etc. that would be necessary to implement this proposed rule change.

1.4 Structure of this Report

The remainder of the report is structured as follows:

- Chapter 2: Physical power system operation;
- Chapter 3: Supply side technologies;
- Chapter 4: Spot market dynamics;
- Chapter 5: Energy purchase risk and contract structures;
- Chapter 6: Impact of 5 minute settlement on contract risk and market operations;
- Chapter 7: Battery economics and system operation;
- Chapter 8: Broader implications.

The report is supported by Appendix 1. References as well as a glossary of terms and definitions used in the report are provided at the end of the report.

1.5 Notes to this Report

The basis of dollars presented in this report is that all dollars are in nominal dollars unless otherwise specified.

2. Physical Power System Operation

This chapter provides a review of current NEM demand, operations and physical constraints, and how that may impact the ability of NEM participants to respond to 5 minute price signals and settlement.

2.1 System Operation - Current Arrangements

The operations of the NEM are composed of the operations of the electricity market and operations in the Frequency Control Ancillary Services (FCAS) markets (leaving aside grid related services). A quick review of this is as follows.

Electricity/energy dispatch and FCAS enablement are undertaken each 5 minutes by scheduled and semi-scheduled generation and scheduled loads as follows:

- Generators and dispatchable loads respectively provide offer and bid prices for dispatch and FCAS service provision;
- A 5 minute (scheduled + semi-scheduled) demand forecast (for each region) is undertaken corresponding to the energy in the 5 minute dispatch period;
- An energy dispatch and FCAS enablement schedule is developed to meet the forecast demand projection accounting for all constraints in the system (such as generator ramp rates and transmission limits). Through the 5 minute period demand and generation are all assumed to ramp continuously from their starting level to the scheduled level; and
- The total cost of providing the schedule is minimised through co-optimising energy dispatch and FCAS enablement.

With no forecast error and linear ramping through each 5 minute period the actual dispatch would follow the schedule. However changes occur such as demand varying from the assumed uniform ramping, demand forecast error, generators varying from dispatch instructions, and major events such as a generator tripping. Non-scheduled generation and non-scheduled demands are also a significant source of demand variability through a 5 minute period and forecast error. These changes are addressed through:

- Regulation FCAS that corrects small changes associated with demand and dispatch errors; and
- Contingency FCAS to address major disturbances.

The efficiency of NEM operations is measured on how the supply side and demand side assets are used to balance supply and demand. We note that currently there are no scheduled demands apart from pumping loads.[3] Given this, the discussion is limited to the supply side.

We firstly consider the energy market (based on no demand forecast error). Demand is supplied as follows:

- By operating generators, where the amount available is given by the level of generation at the start of the period and its ramp rates (up and down);

[3] Noting that smelters are subject to tripping for security reasons and may be interrupted by retailers through their contractual arrangements.

- By Fast Start generators that can be brought on line quickly. These are principally Open Cycle Gas Turbines (OCGT), diesel generators, hydro, and in the future battery systems.

AEMO has the responsibility to ensure that sufficient generation is operating and there is sufficient fast start plant to supply demand in the electricity market.

When demand is flat no change is needed in the amount of generation required and no generators need to be started or stopped (assuming no generator outages). When the level of load (or of available supply) is changing, generation levels are more dynamic.

When demand is increasing (such as the start of an evening peak) additional generation is provided by peaking generation and/or ramping up of existing generation that is already on-line. As for all 5 minute dispatch intervals, generation is scheduled in offer price order (subject to grid constraints, and applicable loss factors), including fast start units with *"inflexibility profiles"*. A scheduled unit with an *inflexibility profile* would be signalled for dispatch, (and based on acceptance by the units trader) would be dispatched at the *inflexibility profile*, until the unit is operating above minimum generation levels. Acceptance by the trader to accept the scheduled commitment signal for the fast start plant is likely to be based on market conditions in the existing and subsequent 5 minute dispatch intervals.

The balance of supply and demand (with no demand or generator forecast error) is achieved through having sufficient fast start inflexible plant and already operating flexible plant.

The amount of inflexible plant available to be scheduled depends on whether the inflexible plant is operating or not. Here we note in all but Queensland, the time for a fast start plant to get to minimum loading level (T1+ T2) from not operating (i.e. cold start) is greater than 5 minutes.[4]

We note that analysis undertaken by Energy Edge for the AEMC[5] on the impact of moving to 5 minute settlement on cap contract volumes[6], appeared to be based on plant already operating at minimum load and/or responding instantaneously to price signals. Because peaking plant is generally not operating before the first 5 minute high price period, the analysis presented by Energy Edge may substantially overstate the response available from peaking capacity.

The maximum increase in demand in a 5 minute period in the NEM is in the order of about 600 MW (see analysis presented in Section 2.2). Thus given that operating generation is not de-committing, fast start inflexible plant will catch-up with such demand increases once committed and at minimum loading levels.

During this time operating plant would be providing the FCAS services needed to address variations from the energy market schedule.

In terms of the efficiency and risk the following are noted:

- Fast start plant are incentivised to start operating on the occurrence of a high 5 minute price signal. This is likely what would occur in an optimised power system;
- The 30 minute trading interval settlement period for energy acts to "smear" the value of peaking supply around the actual 5 minute periods the peaking units are required. In the case of a single 5 minute period (which may be a high price) the arrangements reduce the risk of actual generation in that one 5 minute period;

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4 Five Minute Settlement Working Group: Working Paper No. 1: Materiality of the Problem and Responsiveness of Generation and Load. 6 October 2015

5 Effect of 5 Minute Settlement on the Financial Market, March 2017

6 About 26% for OCGT plant and 18% for conventional hydro.

- Most importantly this provides for a risk profile that permits peaking plant to sell and cover cap contracts, and following from this incentives such plant accept start signals (under inflexibility rules) and offer prices to be dispatched;
- It may also occur that fast start plant unhedged or not signalled by NEMDE to start due to prevailing conditions and may rebid in order to be dispatched after a 5 minute price spike in order to capture the high 30 minute settlement price (perhaps without overly impacting the 30 minute price).

An example of an OCGT plant responding to a 5 minute price signal is shown in Figure 1 below. This is Valley Power OCGT plant in Victoria on Monday 30 January 2017, where it starts operation following a price of $5,500/MWh price in a previous 5 minute dispatch period.

Figure 1: 5 and 30 Minute Energy Prices ($/MWh)

Source: AEMO published data

The current NEM arrangements provide for scheduled generators and scheduled loads to be operated more or less efficiently. In particular peaking generators respond to price signals and generator outages (that may not result in high spot prices).

The conclusion from this is that the current arrangements for scheduled and semi-scheduled generation are well suited to current technologies (e.g. OCGT and hydro plant) and that they provide incentives for efficient market operation.

2.2 Requirement for Peaking Generation

The fundamental requirement for peaking generation in the energy market is driven by the variation required in the scheduled plant fleet.[7] This requirement derives from:

- The variation in forecast 5-minute demand;
- The variation in 5 minute forecast intermittent generation such as wind and solar generation;

[7] We note that FCAS addresses forecast errors within each 5 minute period.

- Reducing base load operating generation;
- Differences in demand and generation from pre-dispatch projections.

To illustrate the current generation mix demand profile, Box 1 below presents the generation mix and demand shape in the NEM for the month February 2017.

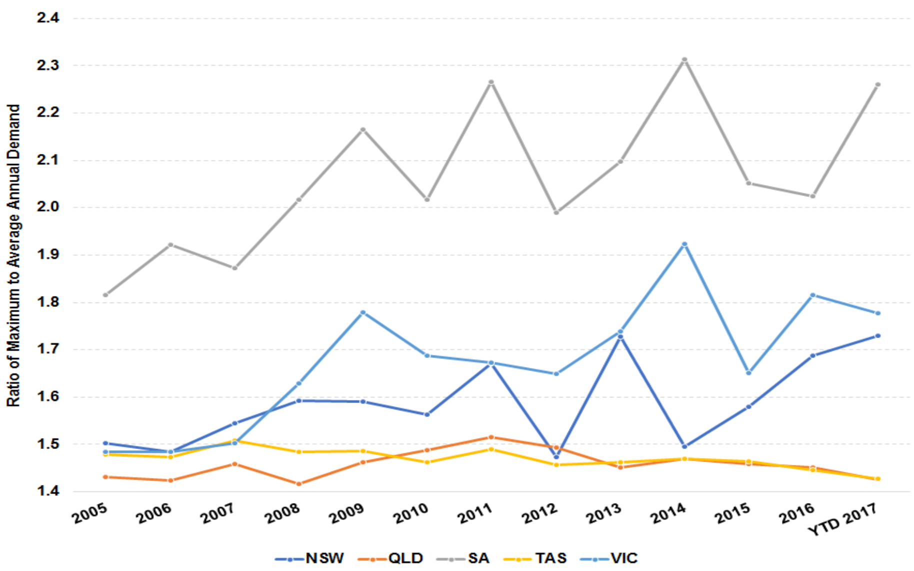
2.2.1 Demand Variation

We note two issues associated with demand variation and the resultant need for peaking generation:

- The increasing variability of peak to average demand;
- The amount NEM demand can increase from one 5 minute period to the next.

Figure 2 below shows the historical trend in the ratio of annual maximum demand (MW) to average demand (MWh) in each of the mainland NEM states up to mid May 2017. This is a measure of the variability of electricity demand and accordingly the risks faced by participants in order to cover that demand.

Figure 2: Ratio of maximum demand to annual average demand by NEM region



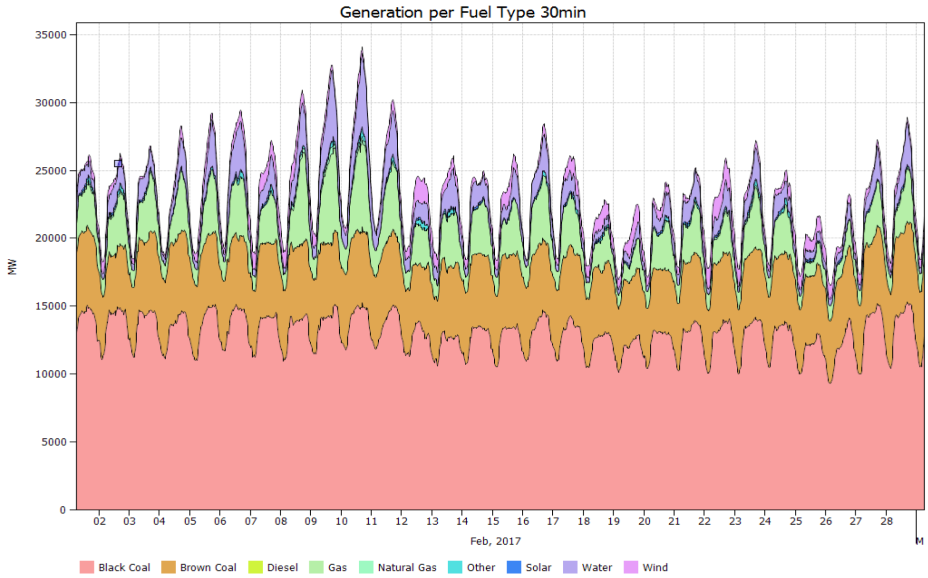
Source: AEMO published data

Demand (and hence load flex) is becoming more variable in NSW, Victoria and South Australia. This is the result of structural changes in the Australian economy away from energy-intensive manufacturing towards less energy-intensive services sectors with relatively higher load flex, and the disproportionate effect that the increase in rooftop solar PV, energy efficiency and consumer's electricity price response is having on average versus maximum demand. This trend in demand (and load flex) is expected to continue for at least the next five years.

BOX 1: NEM Plant Mix by Fuel Type and Regional Demands – February 2017

The requirement for peaking generation in the NEM can be observed through the profile of 5 minute demand and the mix of generation that supplies this demand. This is shown in the graphs below for the total NEM for the month February 2017. From this we observe the following:

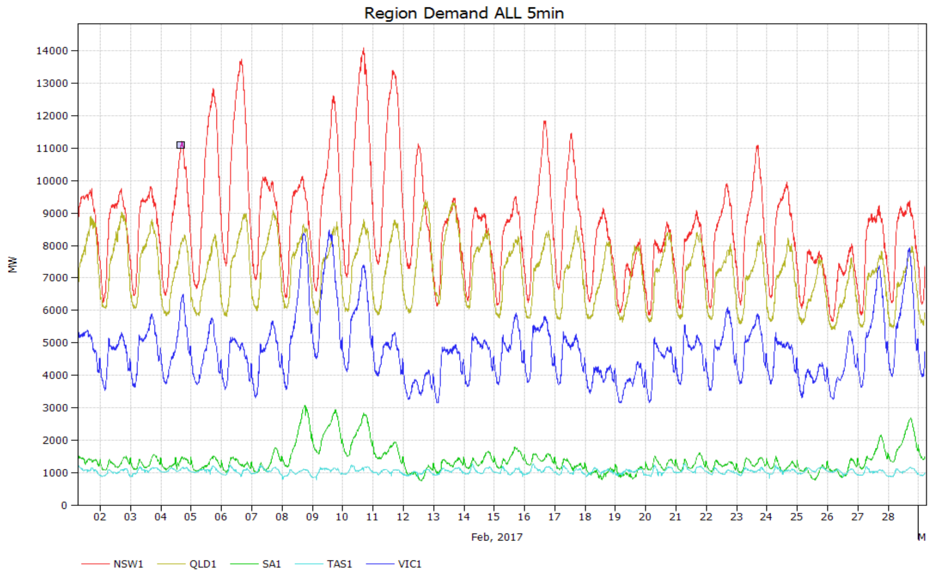
- Coal generation (brown and black) supplies slightly more than the minimum demand level;
- Gas and hydro generation supplies the load shape component which can be as high as 13,000 MW (NEM wide) per day;
- Wind is intermittent and impacts the amount of gas and hydro generation required on a 5 minute and daily basis;
- There are significant demand variations within each State.



February 2017

Total NEM

Generation by Fuel Type

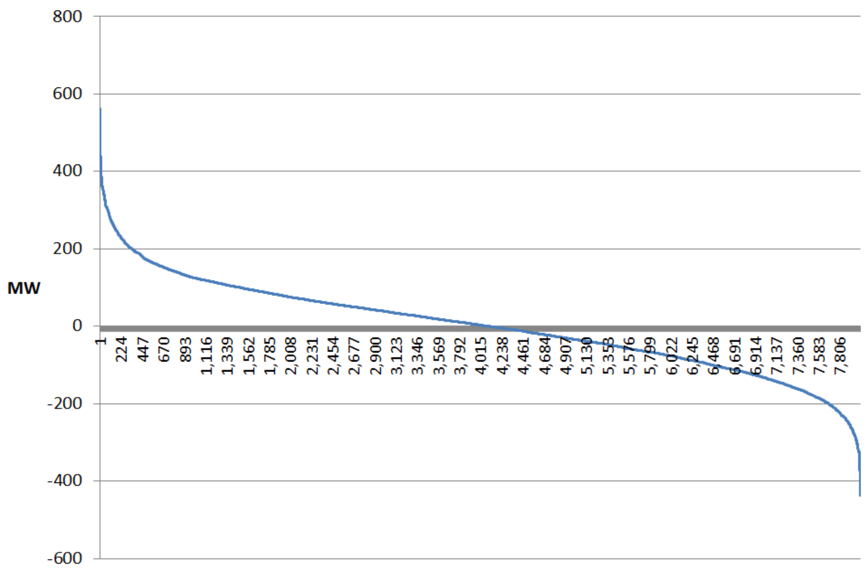


February 2017

Region Demands

The amount 5 minute demand can increase in the NEM is illustrated in Figure 3 below. This shows for the month of February 2017, the distribution of 5 minute demand increase (i.e. the total NEM demand in 5 minute period "t" less that in time period "t-1"). This shows that demand can increase by up to 600 MW in a 5 minute period.

Figure 3: Change in NEM Demand in 5 Minute Intervals – February 2017



Source: AEMO published data and Marsden Jacob analysis

Despite the overall decline in average energy consumption since mid-last decade, it is interesting to note that new record monthly maximum (MW) demands were set in Queensland, NSW, Victoria and South Australia during the 2015/16 and 2016/17 summer periods.

2.2.2 Reduced Base Load Generation

A number of recent generation changes have occurred in the NEM that will and is influencing the need for peaking generation (and FCAS capability). These are:

- The closure of Alinta Energy's Northern Power Station in May 2016;
- The closure of the 1600 MW Hazelwood (Victoria) coal fired power station in March 2017;
- The return to service of 240 MW of mothballed CCGT capacity at Pelican Point (SA); and
- The addition of 170 MW of large scale renewable generation (wind and solar PV), and more than 500 MW of rooftop solar PV installed.

These trends typify the structural change currently occurring in NEM energy supply i.e. decreasing amounts of cheap and reliable fossil-fuelled sources and increasing amounts of higher cost generation and intermittent renewable sources.

With additional renewable energy projects being committed as part of meeting the Federal Large-scale Renewable Energy Target (LRET) and the closure of base and intermediate thermal plant, there will be increased requirements for risk management products to not only cover the higher level of demand load flex, but also the need to firm up the output from intermittent generation sources.

2.2.3 Changes in Spot Operation under 5 Minute Energy Settlement

Under 5 minute energy settlement the physical system is unchanged. However the risk of fast start plant selling caps either to external counterparties, or using these assets to cover their own retail load in the case of a vertically integrated entity, is significantly increased. As indicated in the Energy Edge report and in this report, the level of caps that would be sold or available would be significantly reduced in moving to a five minute energy settlement.

Moving to a five minute energy settlement would result in:

- No smearing of capacity scarcity in the energy market. In fact the Market Price Cap (MPC) – currently $14,000 per MWh, may need to be significantly increased;
- Lower cap contract sales;
- Reduced incentives for inflexible plant to commit;
- Higher spot prices without a supply or demand side response;
- Greater need for more operating generation;
- Greater response by non-scheduled demand that may not have been necessary otherwise; (and reducing efficiency in the scheduled market);
- Inefficient generation operation and increased operating costs.

The market response to an introduction of 5 minute settlement would depend on the costs of the options available to limit energy purchase / supply risk by retailers and vertically integrated portfolios. These options would include:

- Utilising existing generation through increasing the amount of operating generation; and
- Investing in battery storage that can address the response time required to cover a sudden 5 minute high price event.

This balance requires consideration of the costs and performances of the relevant technologies. This is addressed in the next chapter.

2.3 Energy and Ancillary Services[8]

It is important to understand any relationships between the role of ancillary services and the impact 5 minute energy market settlement may have on ancillary services.

First we observe that FCAS is concerned with demand and supply imbalances (or frequency) within the 5 minute dispatch cycle. Hence, moving to a 5 minute settlement period does not

8 While settlement occurs at 30 minute intervals in the NEM, generation dispatch instructions occur at 5 minute intervals. That is, ongoing adjustments in the energy market can be made to contribute to the matching of demand and supply. However, to ensure ongoing adjustments are made within a 5 minute interval, certain generation units are dispatched up or down to correct small imbalances in supply and demand (which manifest in the system as small deviations in system frequency). Typically, these generation units are controlled by Automatic Generation Control (AGC), meaning that those units respond automatically to generation targets issued by the system operator (AEMO). These small adjustments in generation operation are required to maintain system frequency are known as regulation services and apply under normal operating conditions. For major changes in system frequency, due to loss of (say) a major generation unit, then contingency services are provided to restore system frequency. This includes generator governor response and load shedding. Currently there are eight markets for FCAS: two regulation services (regulation up and down); and six contingency services (6 second, 60 second and 5 minute raise/lower services).

involve intra-5-minute operations and thus should in theory have no impact on the current ancillary services definition for FCAS.

Energy and capacity relationship

However the relationship of energy and capacity is different over a 5 minute period compared to a 30 minute period. Over a 5 minute period a generator (or battery) commencing from zero output and linearly ramping to its target needs to reach a generation capacity of 2 MW for each MWh supplied in that 5 minute period. This means a scheduled plant needs twice the capacity to *"cover"* a 5 minute price spike than is being contracted for (which is the average MWh in that period). A non-scheduled battery could overcome this by instantaneously increasing to the required capacity that will deliver the energy required over the 5 minute period. This would require the lower regulation service (and potentially other lower FCAS services) to respond to absorb the excess energy supply. In either case, the cost of cap contract provision have increased substantially.

Non-scheduled Generation and Demand

The current arrangements provide for generators and loads of significant size to operate as non-scheduled demands and generators.[9] Non-scheduled generators and loads increase demand forecast error in the 5 minute dispatch and pricing logic, which acts to reduce the efficiency of the price signals.

Specifically this relates to circumstances where high prices occur in the pre-dispatch market but substantial (unexpected) demand reductions (a price response) occur during the subsequent actual dispatch, resulting in the pre-dispatch pricing and demand being an inaccurate guide as to what may occur. Alternatively this dispatch price uncertainty is also related to a forecast high price occurring in a dispatch interval that wasn't showing in pre-dispatch around which non-scheduled generation and demand then respond in a manner that is oblivious and outside of the AEMO and NEMDE dispatch process.

We also note that many major demand responsive loads (such as smelters, cement works and oil refineries) can generally reduce load in large discrete amounts for limited periods (for example, by rotating the operation of production lines). This can mean that the demand response is not ongoing, but may only last for a single or couple of dispatch or trading intervals. This can lead to the contrary case of inaccuracy when the electrical load returns from its interruption.

As a consequence, it could be argued that the assessment of 5 minute settlement should take account of increases in non-scheduled generation and load response which would likely exacerbate the inaccuracy in price and pre-dispatch forecasts. These issues are being treated through separate rule changes but both matters must be integrated and not treated in isolation to assess the overall impact to the achievement of the National Electricity Objective.

Impact to FCAS

We also note that 5 minute energy settlement would influence the dispatch of generation in the energy market and to this end could impact the capacity available to provide FCAS (regulation and contingency services).

[9] On 10th June 2015 Snowy Hydro Limited (Snowy) submitted a rule change request (AEMC ERC0189) that would require all market customers with loads of 30 Megawatts (MW) or greater and that are price responsive to become scheduled loads. On 24th December 2015 GDF Suez Australian Energy (GDF) submitted a rule change request (AEMC ERC0203) that would require all generators rated greater than 5MW capacity to be scheduled generators – a reduction in the mandatory threshold from 30MW.

To the extent additional operating capacity is required in the energy market (to cover cap contracts), such capacity would not be available for the FCAS raise services. However there may be additional capacity available for the FCAS lower services. The result would be:

- Significant increase in the cost of the FCAS raise services which are relatively high ($10/MWh);
- Potential increase in FCAS lower service costs.

It is noted however that as part of potentially responding to the different incentives provided under a 5 minute energy settlement regime that a range of generator enhancements to the existing installed fleet of generation may be considered by participants. For example this may include changes to control systems to allow for a different FCAS registered trapezium or capability, testing of ramping capability and changes to start times if fast starting can be implemented by peaking plant. However, retrofitting existing technology would incur costs which must be recovered.

It is also reasonable to expect that under a 5 minute settlement regime bidding behaviour and demand response will become more unpredictable and, as a result, there will be a requirement for more ancillary services and therefore higher costs than in the present 30 minute electricity settlement market in order to maintain the system in a secure operating state.

2.4 AEMC and Energy Edge Analysis

To conclude this chapter we provide some observations on the Energy Edge analysis presented as part of the AEMC paper.

Section 4.3.1 of the AEMC's directions paper and Sections 4.4 and 4.5 of the Energy Edge report reviewed the existing fleet of NEM generation assets and assesses their ability to respond and capture high pool prices. A number of important matters are noted in relation to the analysis presented.

Data chosen for available ramp rates included output from generating units at Northern Power station (e.g. refer brown coal line on Figure 4.7) and Hazelwood that are no longer available and running. The analysis should be revised in light of the decommissioning of these coal units.

Figures 4.2 through to 4.7 of the AEMC directions paper and the analysis presented considered observed ramping capacity to be the change in output from one five minute period to the next. What would be an improved and more appropriate way for the AEMC to assess on-line ramping capability is to consider observed ramp up and ramp down capability separately rather than put them both together in the data presented.

Typically with the way the data is presented the ramp down capability will be higher than the ramp-up capability and also include observed unit trips, shutdowns and loss of major plant items (e.g. ID, fans, PA fans, mills, etc.) that will influence the observed ramp down capability. Ramping up capability on coal units in particular is also limited by the ability of coal units to keep up with fuel supply and boilers and other associated equipment to be able to respond to dispatch targets. Typically higher ramp up rates may be available for coal units for very short periods of time but these higher ramp rates are unlikely to be achievable for sustainable periods (e.g. beyond 10 to 15 minutes (or two or three dispatch intervals) due for example to the need to put mills in and out of service). While AEMO registration data just shows maximum ramping capability without specifying which direction, coal units generally and subject to not tripping also have higher unload/ramping down capabilities than ramp up.

It is noted by the AEMC that some peaking plant may have an ability to reduce synchronisation times and/or increase ramping capability. Marsden Jacob is aware that a number of gas turbines installed in the NEM (e.g. Alinta Energy's Braemar units and Snowy Hydro's Colongra units) do already have a facility to fast start and/or load the open cycle gas units faster than the standard/normal start times and ramp rates. In utilising any fast start capability, the owner will incur significantly more wear and tear on the units (approximately three times that of a standard start). The increased costs associated with fast starting peaking plant need to be assessed in light of the risks faced.

The discussion around the theoretical response from fast-start plant in various regions of the NEM does not discuss the myriad of practicalities of operating in the NEM. Box 2 below has been prepared and included to illustrate and discuss the relevant practical issues for fast start plant.

If the strategy or capability suggested for a gas turbine of starting at full speed with no load was to be utilised (noting that generating units cannot synchronise to the grid without getting a start/sync signal from NEMDE/AEMO or else will be in breach of the rules), the unit will incur the notional costs of start towards its planned and expensive major maintenance regime as well as burning gas (around one third of gas it would use compared with full load operation), but without receiving any associated pool revenue. The costs associated with this increased and less efficient running regime would need to be recovered by the generator through higher pool and/or contract revenue and therefore through higher charges from retailers and customers.

BOX 2: Practicalities for operating fast start plant in the NEM

The material provided does not appear to be have been appropriately modified to reflect actual responses and issues and therefore is considered extremely conservative and optimistic in relation to the impact of the potential move to five minute settlement on peaking plant and market participants. The following lists and identifies many of the relevant and practical issues in relation to the commitment of fast start peaking plant in the NEM.

- There are very few, if any, market scheduled generators in the NEM that auto-start (i.e. commence based on start signal issued by AEMO). Trader/operator action is needed to initiate a unit start.
- The unit commitment decision for fast start plant does not happen instantaneously and, in most occasions, there is a delay of a couple of minutes while the situation is assessed and unit is then either committed or start process discontinued.
- It typically takes about 30 second to a minute for any dispatch interval price calculated and issued by AEMO to flow through to the traders' systems.
- When a high or extreme dispatch interval price is realised, most of which are unpredictable, the fast start generating unit may or may not have actually received a start signal from NEMDE[10]. There may also be signals for multiple fast start units to start depending on the extreme nature of the price and event.
- Following the high dispatch price being issued, an operator or spot trader at the organisation has to then assess (and perhaps login if not already on-line) why is the dispatch price high, what is their position, how long is the high dispatch price likely to continue for, how many generating units need to be committed, and then respond by either starting one or many generating units or deciding to avoid the start.
- In any of these situations a rebid will also likely have to be made (band shifting volume down in the case of unit commitment) or T times reset to get a stop signal.
- The rebid will not take effect until at least the next following dispatch interval and normally needs to be submitted circa 30 seconds to a minute prior to the next dispatch interval in order to make it into the AEMO's dispatch engine to get a target or signal for the next dispatch interval. If the rebid isn't received and acknowledged by AEMO in time then the rebid will not take effect until the next further following dispatch interval.
- While peaking plant tends to be generally very reliable, start failure rates of peaking plant would normally be in the range of 2 to 5 per cent i.e. that only 95 to 98 per cent of starts were successful. If a unit fails to complete its start sequence or is delayed due to some issues with the start sequencer then there is a delay while the issue is resolved or start potentially aborted and then, if necessary, another fast start generating unit may need to be committed/started (with any associated rebids) in place of the failed or delayed unit to start.

10 https://www.aemo.com.au/-/media/Files/PDF/Fast_Start_Unit_Inflexibility_Profile_Model_October_2014.pdf

3. Supply Side Technologies

The capability of the supply side to respond to 5 minute dispatch intervals is fundamental to market operation under 5 minute energy settlement. Some of the key issues in the supply side of the NEM over the next ten years relevant to the potential efficiency of 5 minute energy settlement are as follows:

- Ability of peaking plant to supply energy in first 5 minute period when not operating and scheduled to do so;
- Ability of peaking plant to supply energy in first 5 minute period when operating at minimum generation;
- Ability of base load coal plant to supply energy in first 5 minute period when operating;
- Cost of providing new assets that result from the proposed rule change.

These supply side constraints on responding to 5 minute prices are outlined in this chapter. Further detail on the performance and response rates of current and new technologies is provided in Appendix 1.

3.1 Response times of Existing NEM Generation

The ability of generators to respond to 5 minutes price spikes is determined by the physical characteristics of each generation type. The ability of generation plant to respond to 5 minute price signals can be broken down into two components:

- Time from rest (or cold start) to synchronise and ramp to minimum loading – defined by dispatch inflexibility profiles for fast start generators;
- Rate of change in output after minimum loading or when they are already operating (i.e. ramp rates, minimum and maximum loading)

For fast start generators, the time from cold start to MinGen is shown in Table 1 below.

Table 1: Response times of existing generation in the NEM (with FSIP)

Technology	Maximum Capacity (MW)	MinGen (MW)	Average of Max ROC (MW/Min)	Time from Cold Start to MinGen (Min)	Time from Cold Start to Maximum Capacity (Min)
CCGT	297	98	35	18.0	23.6
Coal - Steam (a)	502	125	10	varies	varies
Gas - Steam (a)	300	75	20	120.0	131.3
Hydro – Gravity	231	51	78	5.0	7.3
Hydro - pumped storage	271	138	70	2.5	4.4
Hydro – River	26	13	5	6.0	8.7
OCGT	108	43	20	10.0	13.3
Reciprocating Engine	50	48	14	5.0	5.1

***Notes**:* (a) Usually operating so not required to undertake a cold start in most circumstances in most NEM regions.

Source: Marsden Jacob analysis based on AEMO Inflexibility Profiles and Generation Ramp Rates

This highlights that it can take OCGT and CCGT plant 10 and 18 minutes respectively to achieve MinGen. After this time, both OCGT and CCGT plant can ramp up (based on Max Rate of Change or ROC) and achieve maximum capacity in 3.3 and 5.6 minutes respectively. Clearly, this plant will have a limited ability to respond to 5 minute price signals unless they are already operating. Overall, OCGT and CCGT plant can ramp from cold start to maximum capacity in 13.3 and 23.6 minutes.

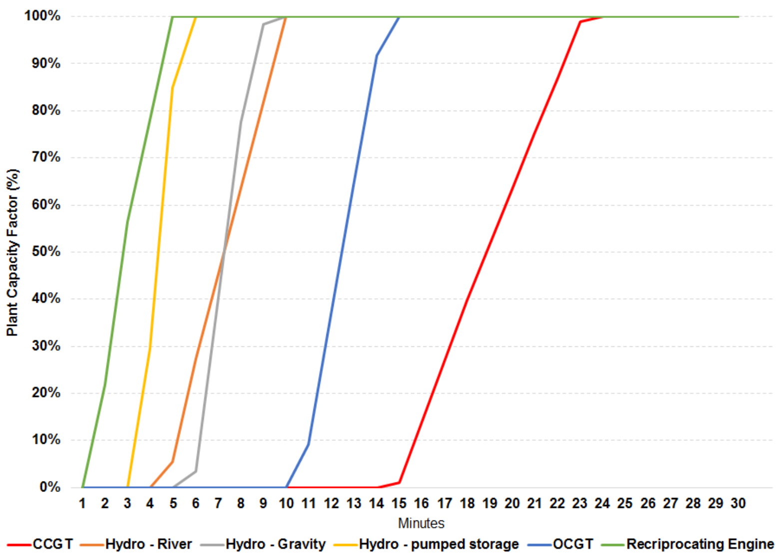
Hydro plant has a much faster response rate and can be at minimum generation between 2.5 to 6 minutes and can be operating at full capacity within 9 minutes (pumped storage can be at maximum capacity within 4.4 minutes).

Typically thermal plant (both coal and gas fired generation) operate as baseload plant and would normally be operating when 5 minute price spikes occur. The ramp rate of this plant (once operating) is relatively slow (maximum ROC up rates of between 10 to 25 MW/min) and implies that they cannot easily take advantage of ramping up into isolated 5 minute price spikes. If coal plant is off-line it is highly unlikely to be able to capture any prices in the next dispatch period unless returning from a unit trip and in a *"hot state"*. If a coal unit is a in a "cold state" it could typically take 24 to 48 hrs all going well to synchronise the unit and then bring the unit up to min gen.

The above table also highlights the rapid response of reciprocating engines in the NEM that can achieve maximum capacity from cold start in just over 5 minutes.

The response rates from cold start to maximum capacity for fast start generation in the NEM is outlined below. The key conclusion from this analysis is that many existing units – especially OCGT and CCGT plant – will not be able to respond to 5 minute price spikes from cold start. As a result, a move to 5 minute settlement could result in this type of plant bidding low prices in the energy market to remain at Mingen (and operating less efficiently) if conditions imply that price spikes may occur in subsequent periods (e.g. high demand or plant outages). This could result in *'out of merit'* order plant dispatch which would result in higher costs being incurred in the energy market.

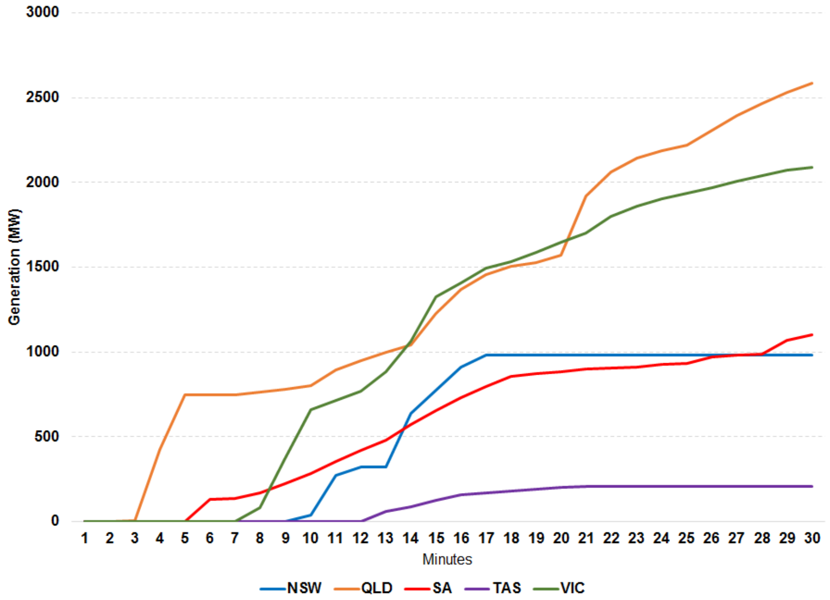
Figure 4: Response Rate of Existing Fast Start Generation (NEM) - Plant Capacity Factor (%) (with FSIP)



Source: Marsden Jacob analysis based on AEMO Inflexibility Profiles and Generation Ramp Rates

The issue of theoretical versus practical operation of fast start plant in the NEM was discussed in Box 2 in section 2.4 of this report. The theoretical response rate of fast-start plant from rest in each region of the NEM is shown below. This highlights that there is very limited fast start capacity even in theory in the NEM that can respond from rest within a five minute period. There is a small amount of generation capacity in South Australia and Queensland that can respond within 5 minutes. In other regions, response rates vary between 7 to 12 minutes.

Figure 5: Theoretical response rate of fast start plant by NEM regions



Source: Marsden Jacob analysis based on AEMO Inflexibility Profiles and Generation Ramp Rates

Under a 5-minute settlement, one-off 5-minute price spikes would not be captured by the majority of fast start generators if they are responding from rest, thereby reducing their revenue and reducing their ability to physically back cap contracts.

3.2 Fast Response Technologies

3.2.1 Generation technologies

Some gas technologies and diesel generators are capable of providing a very fast response, both in terms of time to synchronise and time to ramp up. This includes the following:

- The GE LM6000 (aero-derivative) turbine can ramp from rest to full load in 8 minutes (typically smaller units – 40 MW).
- Reciprocating gas engines (e.g. Wartsila 10 MW units) can respond from rest to full load in 3 minutes.[11]
- Reciprocating diesel generators, which are already installed in the NEM at Port Stanvac, Lonsdale and Angaston, can achieve full load in 5.1 minutes.

11 AEMO registration data indicates that there is 740 MW of non-scheduled, reciprocating engine capacity in the NEM.

The introduction of 5-minute settlement is likely to lead to a significant increase in the amount of this type of plant in the NEM. As highlighted by AEMC in the Directions Paper, when 5 minute settlement was implemented in the Southeast Power Pool in the US, there was a three-fold increase in the capacity factor of internal combustion engines.[12]

However the installation of technology to enable response to 5-minute pricing without market efficiency benefits is simply a replication of assets, with associated increased costs which would be passed through to customers.

3.2.2 Demand response

Demand response is the ability of end users (retail customers) to reduce their electricity use (or load) when requested by either a retailer, a market/system operator or network company. Demand response can be a retailer's response to avoid paying high wholesale spot prices (unhedged) or an attempt by the system or network operator to maintain the reliability of the grid.

Based on our experience in both the NEM and the Wholesale Electricity Market (WEM) in Western Australia – in the case of the WEM over 10 per cent of reserve capacity is provided by demand response resources (560 MW), the majority of demand response resources requires more than 5 minutes to be activated. However, there are end users who are able to respond rapidly to demand response. For example, aluminium pots or silicon kilns can drop their electricity load within seconds for a temporary period of time (usually for around 30 to 90 minutes).

It is our understanding that demand response resources in New Zealand could also provide regulation services (260 MW of load was offered into the North Island market in May 2016). The largest potential contributors come from heavy industry, pulp and paper, and hot water heaters.

While demand response could be a resource that could more actively participate in spot markets, they are only likely to be a minor contributor to meeting NEM demand in 5 minute intervals.

3.2.3 Battery storage

Battery storage is regarded as a technology that could be deployed in the NEM to provide a range of services to help maintain the physical demand and supply balance that is required to operate an electricity system. This will be increasingly important as more intermittent generation is added to the NEM over the next decade.

The response time of battery storage (i.e. time taken to reach its maximum power output from dormant status) is milliseconds as shown in the table below. In addition, the output from battery storage systems can be tightly controlled (using management control systems), which makes them suitable to provide regulation services in the NEM.

[12] http://www.ferc.gov/whats-new/comm-meet/2015/091715/E-1.pdf

Table 2: Response time of battery storage

Battery Type	Response Time
Lead Acid	5 to 10 milliseconds
Advanced Lead Acid	5 milliseconds
Nickel-cadmium	Several milliseconds
Lithium-ion	20 milliseconds
Sodium sulphur	1 millisecond
Sodium nickel Chloride	100 milliseconds
Zinc bromide	1 millisecond

Source: Cavanagh K, Ward J K, Behrens S, Bhatt A I, Ratnam E L, Oliver E and Hayward J. (2015). Electrical energy storage: technology overview and applications. CSIRO, Australia. EP154168

Apart from their ability to provide regulation services, battery technologies have the potential to provide a variety of other services in the NEM. This includes the following:

- Demand smoothing through energy arbitrage (time shift energy from low to high value periods);
- Reduce energy price risk in the spot market (noting that their ability to provide cap contracts is limited);
- Network support services:
  - location critical and need may change over time;
  - oversizing the inverter can be used for reactive power control;
  - unclear how effective batteries can be in managing thermal constraints given the storage limitations.
- Reduce network demand to reduce future network investment and associated access charges. However the capacity to do this is unclear;
- For end uses with intermittent generation (e.g. rooftop PV), reduce dependence on grid energy (high variable price – 26 c/kWh) and less spill of generation into the grid at low feed-in tariff rates (7 c/kWh).

The ability of batteries to provide a range of services is one of their key advantages (although they cannot provide these services simultaneously). The key disadvantage of battery storage is that they only have extremely limited supply (typically 1 to 2 hours of energy storage) and are currently high cost (~$1000 per kW).[13]

A move to 5-minute settlement has the potential to increase the value of battery storage in the spot market in the NEM since they are likely to be the main technology which can respond immediately to high price spikes in the NEM. This may be dependent on reforms in the ancillary services market. Most other fast-response technologies (e.g. reciprocating engines and diesel generators) will not be able to respond in the first 5 minute period and will have to wait until the 2nd and 3rd 5 minute periods to benefit from a price spike.

[13] ` Assuming the battery can discharge its maximum capacity for 1 hour (e.g. 25 MW/25 MWh battery configuration)

However the energy limitations of batteries mean that that are not suitable on their own to supply cap products.

One way for generators to maximise the value of price spikes is to co-locate batteries within an existing or new power station. For example, co-locating a battery with a gas turbine will allow the battery system to discharge while the gas turbine synchronises and ramps up to maximum capacity. In addition, co-locating batteries with wind or solar farms will allow intermittent plant to provide fixed blocks of energy in limited trading intervals. This can assist in enabling wind and solar farms to provide *'firmer'* supply contracts to off takers and receive a higher contract price in return. However there would be a high cost associated with such developments.

Most of benefits that we have discussed above arise if the battery is sufficiently sized to participate in wholesale electricity markets. However, it is likely that users with embedded generation (e.g. rooftop solar) will install battery storage because of current financial incentives. For example, low feed-in tariffs and high consumption charges will drive customers with rooftop PV to install battery storage. However, to be useful in the spot market with 5 minute settlement, some sort of aggregation of these units, which are installed beyond the meter, will need to occur. Technical solutions for discharging and recharging a portfolio of storage units beyond the meter will need to be developed.

As previously noted, the installation of technology to enable response to 5-minute pricing without market efficiency benefits is simply a replication of assets, the costs which would be passed through to customers.

4. Spot Market Dynamics: Past and Future

This chapter reviews the dynamics of spot price spikes, the drivers of this price and the profile of spot price spikes moving forward. In particular, what kinds of generator bidding behaviours and price outcomes could emerge under five minute settlement as compared with 30 minute settlement? This is fundamental to the operation of the market *"top end"* and the efficiency impacts of 5 minute energy settlement.

The AEMC directions paper discussed the incentives influencing operation and bidding processes under the current 30-minute settlement process when price spikes occur in the market. Two types of price spikes were considered:

- Late price spikes – where the price spikes in one of the later 5-minute intervals within the 30-minute settlement (trading) interval; and
- Early price spikes – where the price spikes occur in one of the earlier 5-minute intervals within the 30-minute settlement intervals.

The AEMC paper canvassed issues around rebidding practices following early price spikes – where generators ***may*** have an incentive to alter bids or withdraw plant in order to participate in the later five-minute periods (regardless of whether the dispatch price is lower for these intervals) in order to gain access to revenue driven by a relatively higher average price across the 30-minute settlement interval.

The AEMC also points to changes in bidding behaviour that appears to have shifted price spikes away from dispatch interval six to dispatch interval one. (p. 35).

4.1 Bidding In Good Faith Rule Change

The *Bidding in Good Faith* Rule Change, which replaced the requirement for offers to be made in good faith with a prohibition against making false or misleading offers, commenced on 1 July 2016[14]. The AEMC's directions paper for the current Rule Change indicates that prior to the change the mismatch or misalignment of dispatch and settlement resulted in rebidding whereby a generator may withdrawal capacity and cause an increase in the spot price in the last five minute dispatch interval of a 30-minute trading interval. That by doing so, generators are able to earn a higher price over the 30 minute interval[15]. The AEMC goes on to state:

> *Initial analysis suggests that since the rule change was made, this behaviour has declined*[16]*.*

Contrary to the suggestion by the AEMC, the analysis undertaken by independent consultants, ROAM, as part of the previous rule change, did not find evidence of systematic rebidding. Rather, there was evidence to suggest a decline in the number rebids for all 5 minute intervals over time.

Consultants Ernst & Young in a report to the AEMC[17] noted the following:

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14 For more information refer to the AEMC website: http://www.aemc.gov.au/Rule-Changes/Bidding-in-Good-Faith

15 AEMC (2017) *Five Minute Settlement*, directions paper, 11 April 2017, p. 16-17

16 AEMC (2017) *Five Minute Settlement*, directions paper, 11 April 2017, p. 18

> *The key challenge in testing the effect of late rebidding on wholesale and contract markets is identifying whether wholesale market outcomes are caused by late rebidding. The statistical analysis conducted in not appropriate for identifying this causal relationship. Even sophisticated back casting techniques that could be applied to determine the impact of historical strategic late rebidding on wholesale prices would be underpinned by the assumption that removing strategic late rebidding does not affect other bidding behaviour.*
>
> *Therefore, although the statistical analysis shows that there may be relationship between late rebidding and price volatility and/or increases in contract market prices, this does not prove that eliminating or reducing strategic late rebidding would negate these outcomes. (p.21)*

4.2 Spot Price Spike Outcomes

4.2.1 Spot Price Spike Trends

A review of historical price spikes over the past 5 years (2012 to 2016) shows that 30 minute price spikes over $1000/MWh involved only one 5 minute price spike 83% of the time[18]

The tendency (except for major system events or incidents) for price spikes to be short-lived is consistent with the emergence of fast start plant, increased interconnection and demand response. The reasons for this are complex but include:

- Nature of supply demand/curve has become a lot steeper so small changes in supply or demand can move the price outcome around significantly;
- Generators responding rapidly in the event of a price spike to offer more volume into the market at lower prices;
- Rapid responses from both demand and supply to prices spikes; and
- AEMO's pre-dispatch not forecasting prices accurately (for a myriad of reasons including, movements in non-scheduled demand or intermittent generation output, outages, constraints, etc.

Moving forward, with 30 minute energy settlement remaining the dynamics of spot price spikes would be expected to maintain the predominant early single 5 minute spike profile.

4.2.2 Spot price Spikes under 5 Minute Energy Settlement

Under 5-minute settlement, every price spike can be considered a "late price spike", with no incentives remaining for generators to make efforts to participate and lower subsequent 5 minute prices. As previously noted, late price spikes reduce the incentive for generators to enter the market to access the shared benefits from the price spike are limited.

This means that the impact of 5 minute energy settlement could be to increase the number of price spikes in a 30 minute trading interval.

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17 Impact of late rebidding on the contract market, Final report to the Australian Energy Market Commission, 11 September 2015.

18 Such analysis was also conducted by Russ Skelton and Associates in a report prepared for the Australian Energy Council on 5 Minute Settlement (March 2017) where all price spikes over $1000/MWh for the period 2012 to 2016 were analysed and found that price spikes occurred for only one dispatch interval 83.2% of time.

There could be a market reaction to this. Limitations on accessing relatively higher price events are physically limited by plant response times. This includes both T times where the plant commences operation from a cold start, and ramp rates where the generation is already in operation. One outcome of the change in settlement interval may be that more generation units move to operating at low levels at all times in order to be better able to respond quickly to potential high price events. By remaining on, these plants may be operating less efficiently than they would under the 30-minute interval, but they avoid missing the higher price events completely due to slower start-up times.

4.2.3 Difficulty in predicting extreme price events

The Energy Edge report notes the considerable uncertainty (refer Table 5, page 54) that pre-dispatch is highly inaccurate in predicting five minute price volatility. In particular it is noted by Energy Edge (p.54) that "*even 5 minutes prior to the relevant five minute period, pre-dispatch pricing is highly inaccurate and therefore a large proportion of high price events are unanticipated*". It is therefore somewhat surprising that the following section then describes the analysis presented as containing "*a degree of conservatism*".

It could equally and readily be argued that due to the uncertainty of prices, the need to assess what is happening and then respond that the analysis then presented contains a degree of optimisation or prefect foresight of events, unit commitment and response that is unlikely to be achieved in practice.

5. Energy Purchase Risk and Contract Structures

This chapter outlines current risk management products offered in the NEM and participant risk management policies and how they may be impacted by the adoption of 5 minute settlement.

5.1 Managing Wholesale Energy Purchase Risk and Contracting

The uncertain and variable nature of future spot prices (half hourly to annual average) will increase further under 5 minute settlement and will require an increase in the volume of risk management products (e.g. caps, peaking generation, etc.) to reduce risks to both generators (suppliers of these products) and retailers (typically buyers). For generators, these risks arise from uncertain future revenues, while for retailers these risks are associated with uncertain costs while offering their customers fixed priced tariffs.

For this reason NEM participants typically seek to hedge large proportions of their exposure to spot prices through buying or selling financial contracts or alternatively through vertical integration. The basic form of a hedge contract exists where two parties agree to exchange cash so that a defined quantity of electricity over a nominated period is effectively valued at an agreed strike price.

Due to the extreme price volatility as well as the sustained high or low levels of prices that can be seen in the NEM, without prudent risk mitigation wholesale market participants can have high levels of financial exposure to the spot market. A variety of hedging and risk management products are therefore used by most if not all market participants to manage these risks and, clearly, the effectiveness of the variety of hedging strategies and products would need to be reassessed by participants in light of a change to market settlement arrangements.

It is also recognised by both Energy Edge (Section 6.3.4) as well as the AEMC (Section 7.2.2) that there may also be potential contractual disputes and re-opening of electricity contract arrangements as a result of the rule change to 5 minute financial settlement due to changes to the price source, market rules, etc. Even noting the potential that the implementation of a new rule on financial settlement may not take place for several years, the cost or potential re-opening of existing electricity contracts has not been considered by Marsden Jacob as part of this report. It is noted however that this may not be a non-trivial matter and will involve considerable time and legal and economic resources.

5.1.1 Energy Trading Policies and Risk Management

As part of prudent management and in meeting the requirements of holding a financial services licence, electricity participants will normally have in place robust energy risk management policies that may report to a separate Board Sub-Committee and/or management committee specifically on energy risk. Typically these energy risk policies are reviewed at least annually, show version numbers, date approved and high level detail of changes from the prior policy version. Where organisations have only small positions that need to be managed these policies and procedures may be extremely limited and fair less comprehensive than would be found at a large organisation.

The document would be comprehensive and contain a range of areas including:

- Organisation's risk appetite – this can vary quite considerably between organisations;
- List of energy risks;
- How risk is measured;
- Risk and position limits (e.g. earning at risk, capital at risk, market prices and scenarios/sensitivities, hard and soft minimum and maximum hedging limits, etc..);
- List of approved energy products (e.g. electricity, gas, renewable energy certificates), approved markets, etc.;
- How breaches are managed and reported;
- Wholesale energy credit policy (can either be in the energy trading policy or in a separate policy document);
- Delegations – who is authorised to trade on the organisation's behalf (sometime also in a separate document);
- Segregation of duties (front, middle and back office reporting lines to ensure ring fencing of duties and responsibilities).

The energy risk framework developed would normally:

- Identify the risks;
- Measure the risks;
- Manage the risks; and
- Monitor and communicate the risks to management.

Risks, as they related to energy risk, are typically characterised as:

- Market Risk;
- Credit Risk;
- Liquidity/ Funding Risk; and
- Operational Risk, Legal and Regulatory Risk.

The Trading/Energy Risk Policy would normally provide detailed guidance on the metrics used to calculate market, credit, and liquidity/funding risks, the processes to review the methodologies and methods, and the estimation of the risk parameters used in calculating them.

Under the rule change being consulted on currently by the AEMC, in potentially moving from 30 minute financial settlement to five minute financial settlement it will be important for any participant to model and assess what the additional risks may be on their business and accordingly what changes would need to be made to their risk policies and practices.

(1) Risk management and product requirements

If the market changes to five minute settlement, risk limits will need to be reviewed by all participants. However, it is likely that retailers will still hedge at similar levels after the introduction of 5 minute settlement as they do today.

While there will still be similar demand for peaking risk products, due to prevailing technical characteristics, it is likely that existing peaking generators will have less volume to offer (both to cover their own retail loads as well as to sell to others). A very brief summary is included below of some of the issues facing retailers and generators.

Retailers

- Will still need to be prudently hedged
- Risk limits need to be reviewed
- Will need to respond to lower cap availability from traditional sources
- Costs will be passed-through to customers

Generators

- Risk limits need to be reviewed
- Cap contract pricing will need to be higher, reflecting higher risk in selling this product
- Potentially lower contract levels – changed behaviour
- If less cap contracts are sold by peaking generation due to the change in market design, likely that cap contract revenue shortfall for these generators will attempt to be recovered in higher spot prices that will ultimately be paid for by retailers and customers
- More potential demand for outage insurance and other risk/insurance products
- Part loading and less efficient operation of in-service generating units
- Consider cost/benefit of other capability options (e.g. fast start/load)

5.1.2 Load Shape, Uncertainty and Mismatch

Driven by a range of factors including weather, processes and operating hours, one of the significant challenges facing retailers and customer loads is that the electricity load for that same customer can and does vary from one half hour to the next as well as by day type and season throughout the year. A retailer (or generator) will seek to manage the risk associated with changes to its customer loads (or generation output) on a regional basis using a variety of products and will also consider its overall NEM position as well as inter-regional positions.

While output or load can vary on a half hourly basis, most wholesale electricity hedging products available are generally flat structures, with the same volume in each relevant time period be they flat (all time periods) or peak (7 am to 10 pm on working weekdays). Accordingly there can be significant periods of under and over hedging of load compared with the hedging structure that has been put in place.

A hypothetical example for a typical day and load profile with a simple hedging structure to manage the risks associated with a generic load profile is shown in Figure 6 below. In this figure the dotted lines represent the range of electricity demand from customers that the retailer is financially responsible for and the shaded areas represent the coverage provided by different hedging instruments.

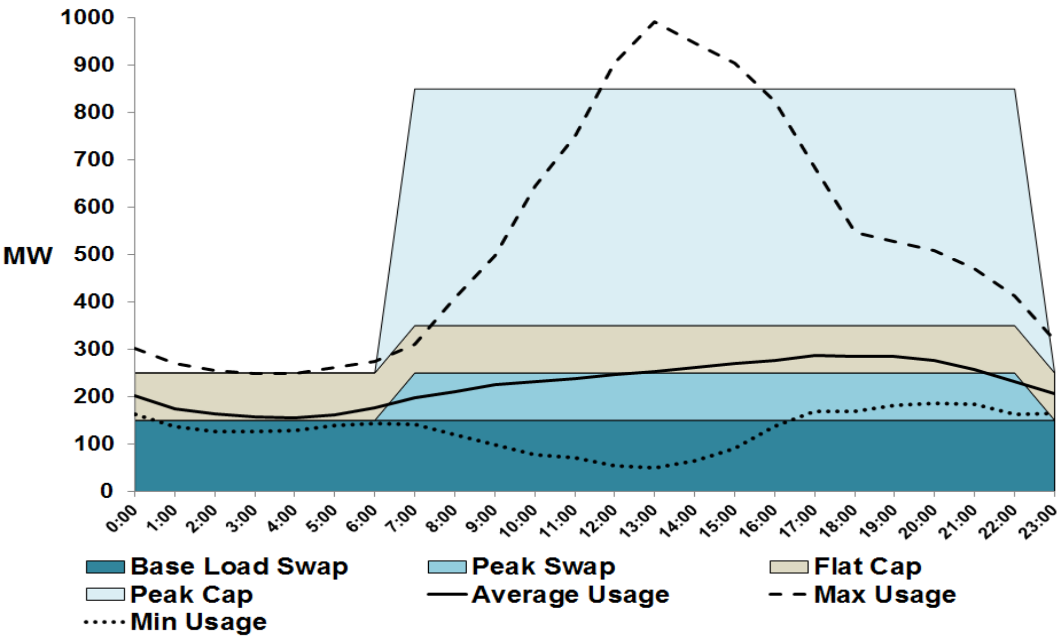
Due to the shape of the load, the correlation of its demand to spot price, the mismatch between the block structured hedging instruments and the out turned load there will be associated risks that need to be priced or allocated between the buyer and seller of the hedging contracts for the electricity load.

In particular if the electricity load shape needing to be hedged has a high correlation with peak electricity prices (such as a commercial building with peaky air conditioning and business usage profile) a premium will be charged to manage this risk whilst if the load (such as a water pumping load) is inversely correlated to higher pool prices and risk, a discount to the flat contract or pool prices may be plausible.

Due to the mismatch between actual and forecast load (could be due to unexpected production from an intermittent generation source) as well as the mismatch between block hedging structures and the quantity itself, there will be a cost of under or over-hedging (i.e. the risk of under hedging and the additional cost of over-hedging). This cost of imperfect hedging will need to be borne either by the customer/retailer directly or else that assessed charge will be incorporated and paid for as an additional premium to cover the flex required to manage a whole of meter load shape.

The additional risk associated with moving from 30 minute settlement to five minute settlement for the seller will require consideration of additional costs and risks that will be passed through to the buyer/retailer and ultimately customers.

Figure 6: Illustration of Sample Hedging a Load Profile in the NEM



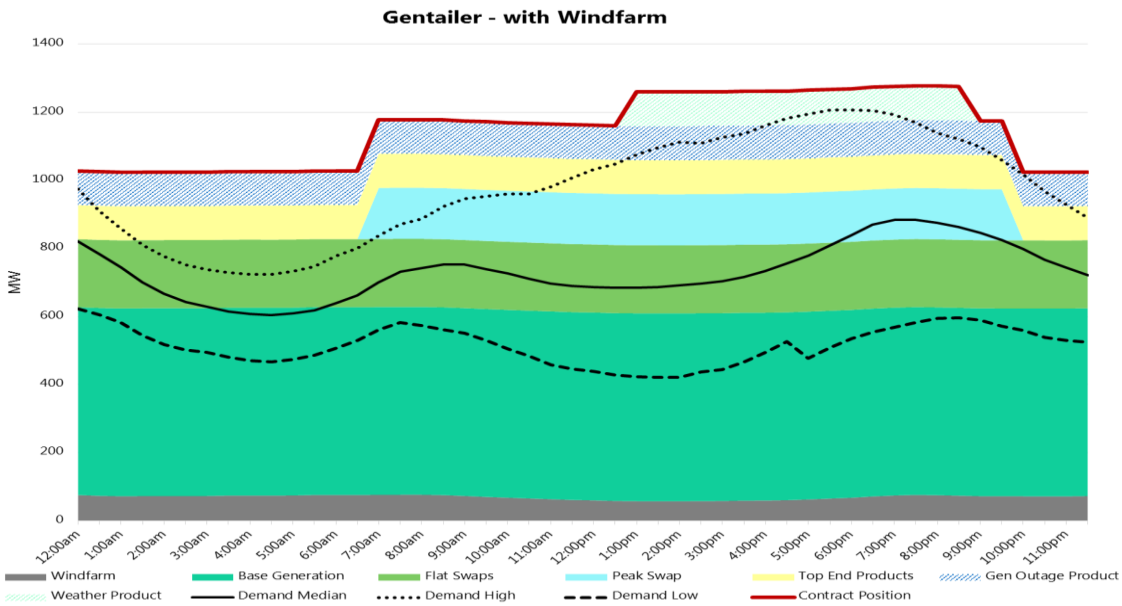
It is noted that the Energy Edge contract analysis presented focuses on the observable traded market and doesn't consider in any detail the impact for the larger vertically integrated players. For these large gentailers it is far easier with their generation and portfolios available to absorb the variable output associated either with demand fluctuations or output from intermittent generation sources within their larger portfolios. Many of these gentailer participants also purchase the output from multiple intermittent technology projects in the same NEM region but in different locations.

Most if not all larger gentailers already have access to diversified generation portfolios including large gas and/or coal fired generation portfolios with varying degrees of ramp rate and start up flexibility. These generators were originally commissioned to either provide energy (base load and intermediate coal and gas units) or provide flexibility and risk management (open cycle, combined cycle gas plant and diesel generation). Extending the operation of these flexible generation assets to cover the output uncertainty in relation to purchasing the intermittent energy output from a renewable source is a natural extension and can be done with very little additional cost (except of course incremental fuel and any additional starting cost requirements).

Whether or not the intermittent output is from a wind or a solar farm, understanding the robust short term forecasting of the expected generation output is extremely important for position management. Accurate forecasting allows the participant to then determine in a timely and orderly manner what additional generation output may need to be taken in or out of service, ramped up or is there a cheaper available alternative (e.g. taking prudent spot exposure or buying/selling additional hedge cover). This is quite a contrast to many of the second tier retailers who may not have many or any physical or financially controlled generation assets at their disposal and have to purchase additional products and/or take on additional risk to manage intermittent generation output risk.

Shown in Figure 7 below is a typical and example structure of a portfolio for a large gentailer for a particular day comprising a range of generation sources and hedging products, including the output from a portfolio of wind farms (with a level of output variation), base generation (provided by coal and/or gas fired generation) and a bought level of flat swaps and peak swaps.

Figure 7: Sample regional electricity hedge position for a large gentailer



Top end products shown on this chart would include a combination of demand side management, settlement residue auction units (SRAs) and embedded or peaking diesel generation. An assessment of the likely contribution/effectiveness of these top end products to the hedge position would typically be made by the middle office to determine what level of instrument derating was appropriate given their non-firm nature. At the top end of the portfolio for risk management purposes these larger gentailers are also likely to have in place in their portfolio positions some combination of a generator outage insurance product and potentially limited number of tailored weather products (e.g. hot temperature, low or high wind output, etc.).

The demand levels shown on the chart illustrate how the position would appear at different levels of expected demand if the position was the same over a longer period (e.g. calendar year or a quarter). In order to manage the situation of low demand, the gentailer can of course reduce generation output to a technical minimum level or else take generation units off line to reduce the level of over-contracting relative to load. As an alternative to swaps, generation outage and top end products, cap contracts could also be bought (or sold), but this has not been shown in the portfolio illustration provided (an alternative example portfolio structure can be found in Figure 6).

In order to manage uncertainty associated with medium to long term energy prices and especially where they face exposure between their bought and sold positions, it would also be typical for larger retailers and generators (as well as financial intermediaries) to also enter a range of option contracts (e.g. put and call agreements and options to extend for power purchase agreements) that can be exercised for a defined term with a mutually agreed period of notice.

As additional intermittent generation output is added into their portfolios through signing up additional output to meet their RET obligations, a number of observations are made below for these larger gentailers:

- Energy from intermittent generation is increasingly being substituting for coal-fired generation and/or reduced need to burn larger volumes of gas through gas-fired generation (more flexible operation is therefore potentially needed and required than seen historically);
- Price distributions and load shapes are and will continue to change, altering hedging strategies and risk profiles and policies;
- Reduces and changes the levels of firm swap required;
- The need to manage portfolio flex increases, both due to load variability as well as uncertainty of volumes produced from intermittent sources;
- The need for alternative and potentially additional wholesale risk management products will increase, most notably for caps, weather products, additional peaking generation, etc.; and
- A move to five minute settlement will reduce the effectiveness of the gentailers peaking plant in managing five minute pricing risk. Reducing both their own contract coverage from their own generating plant as well as potentially reducing the amount of cap or risk management products available to other participants.

5.1.3 Types of hedging products

A range of hedging products exist to allow buyers and sellers to trade electricity in quantities that vary throughout the day and are unpredictable. It is understood that the AEMC and Energy Edge have a strong appreciation of the types of hedging products available in the NEM and the following is not a comprehensive list by any means, but lists three main and more common hedging products which are likely to be materially impacted by the potential introduction of a five minute settlement.

Vertical integration

With increased vertical integration and consolidation occurring across the NEM, hedging a retail load profile with load uncertainty is increasingly being undertaken through retailers owning or contracting directly with generation, with supporting derivative contracts, most notably swaps and caps.

Impact with proposed five minutes settlement: peaking plant not on-line will be limited by its ability to ramp up within a five minute dispatch interval to cover fluctuations in pool prices. Especially impacted where this generation is off-line and the price is not forecast.

Swaps

Whilst monthly electricity futures products do exist, unlike in South Australia and Tasmania liquidity in the NSW, Victoria and Queensland regional electricity markets remains relatively high. This means it is theoretically possible but difficult to adjust positions to a monthly resolution through over the counter derivatives or futures contracts. Standard swap products are generally flat in volume (i.e. same volume in all time periods) for calendar quarters or annual periods.

Flat swaps, bought or sold on a quarterly or annual basis, are a readily accessible and anonymous channel through which any NSW retailer or wholesale market participant can gain exposure to the market and manage risk. The best and most prudent approach adopted by most participants is to build up positions slowly in small volumes for example, by buying or selling in forward volume on a quarterly basis. In addition to trading with generic ASX electricity futures products, flat swap products can also be traded over the counter (OTC). Electricity futures and options contracts are listed by the Australian Stock Exchange (ASX)[19] on the four major regions (VIC, SA, QLD and NSW).

Note that sculpted volume swap contracts (i.e. different volumes potentially in each half hour rather than same volume in all time periods) need to be negotiated bilaterally through the OTC market.

Impact with proposed five minutes settlement: physical participants selling swap contracts to hedge their positions will require more certainty in relation to on-line generation and the distribution of prices that make up the swap (e.g. above and below $300/MWh prices that together make a up the firm swap price). As discussed further within this report, depending on the materiality of changes and risks to above $300/MWh prices there is likely to be a change in the pricing of swap contracts reflecting the risk of above $300/MWh prices within that swap.

Caps (futures or OTC)

Buying or selling of a caps (involving the payment of an agreed premium and generally with strike prices of $300/MWh) through OTC or futures markets is an extremely common electricity product traded in the NEM. It is a potential revenue source for generators and generally used as price protection for risk management purposes by retailers. A range of C&I customers have shown interest in purchasing cap type products to protect against pool price outcomes where they are taking on spot exposures. Different strike price levels of caps can also be negotiated bilaterally. More complicated cap products (captions) can also be developed and triggered under certain conditions.

Impact with proposed five minutes settlement: Likely to become even more of premium product with peaking plant either needing to be on-line, or needing higher cap premiums and/or spot revenues, in order to cover the risk/cost of either having to be on-line more often and running in a less efficient manner, or to cover the cost of not being able to physically defend the cap sold position due to an inability to forecast 5 minute price spikes prices and dispatch plant appropriately.

[19] https://www.asxenergy.com.au/futures_au

6. Impact of 5 Minute Pricing on Contract Risk and Market Operations

With potential changes from 30 minute financial settlement to five minute financial settlement, many existing generators that are providers of peaking capacity into the spot market, as well as a myriad of risk management products into the contract market, will be materially limited by their technical abilities and operating envelope to be able to respond to five minute pricing. As a result of these technical limitations (highlighted in Chapter 3), Marsden Jacob has made an assessment of the likely impact on cap contract availability in the mainland NEM.

6.1 Cap Volume Reduction

This section presents analysis of the level of cap contracts needed and the potential reduction in cap contracts associated with a move to 5 minute pricing.

6.1.1 Load flex and required cap contracts

To assess the impact of this proposed rule change, the amount of peaking cap contracts needed in the mainland NEM regions needs to be estimated. While a number of approaches could be suggested, Marsden Jacob has examined the underlying demand characteristics, load flex and then assessed what mix of instrument and plant may be reasonable and appropriate to manage the energy risk associated with this load.

Table 3 has been prepared using the AEMO 10% POE demand data and compared with average regional load levels to ascertain the level of load flex needed in the mainland NEM to be covered through a mixture of on-line and off-line generating plant. While there may be some potential arguments that regional load diversity may reduce coincident demand, regional exposures and positions on extreme days need to be considered, assessed and prudently managed. While load flex could also be covered at the top end to a small degree by other risk management products as well (e.g. weather derivative products, settlement residue auction units, demand management, etc.) a conservative view has been taken of demand and what level of peaking generation is required that needs to start to cover this load level.

Table 3: Maximum Demand and Load Flex required in NEM regions

Region	Maximum Demand (MW)	Normal Maximum Demand (MW)	Flex (MW)
NSW	14,155	9,000	5,155
QLD	9,257	7,000	2,257
VIC	9,948	6,000	3,948
SA	3,158	1,500	1,658
NEM	36,518	23,500	13,018

6.1.2 Reduced Level of Cap Contracts

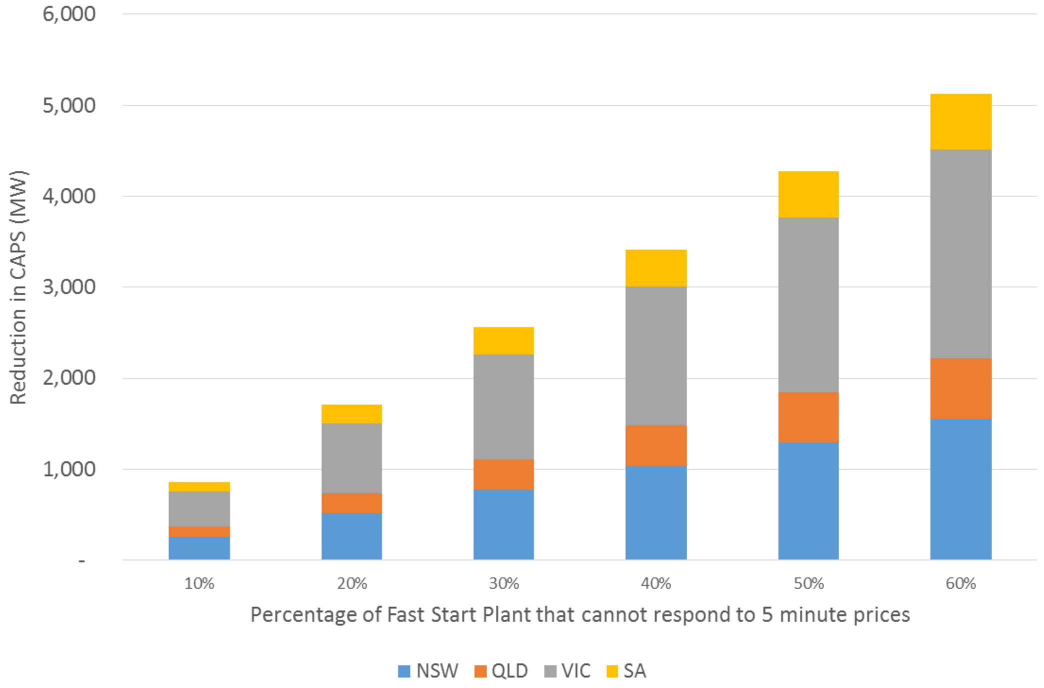
Using a range of operating scenarios reflecting the technical operation and capability of the peaking plant, Table 4 has been prepared to indicate the level of cap cover that may potentially be unavailable in the mainland NEM taking the reduced capability of peaking generators into account to offer these products under a 5 minute settlement regime. The table has used the conservative assumption that peaking generation can supply 50% of the required energy in the first 5 minute period.

Table 4: Reduction in Cap Volume – Non-operating plant achieve 50% operation in first 5 minutes

Region	Existing Plant On line (MW)	Existing Plant Spare Capacity (MW)	Plant Required to Start (MW)	Effectiveness of Plant required to Start	Reduction in CAPS (MW)
NSW	9,000	2,557	2,598	50%	1,299
QLD	7,000	1,160	1,097	50%	549
VIC	6,000	112	3,836	50%	1,918
SA	1,500	644	1,014	50%	507
NEM	23,500	4472	8,546		4,273

However it is most unlikely that peaking plant could provide 50% of the required energy in the first 5 minute period. Figure 8 below presents the level of cap volume reduction (by State and total) based on the effectives of peaking plant to supply the first 5 minute interval ranging from 10% to 60%.

Figure 8: Potential Reduction in Caps provided by Peaking Plant in the NEM



It is the opinion of Marsden Jacob, based on the generator response data available, that the percentage of 5 minute energy that can be supplied from existing peaking plant is substantially less than 50%.

With increasing intermittent generation being substituted for baseload thermal plant or to meet electricity demand as part of the LRET, going forward there will be an increase in the demand for cap type insurance products from a range of participants.

6.2 Peaking Plant Revenue Impact

The reduction in response to supply 5 minute price spikes is reflected in an expected reduction on peaking plant revenues. This section puts this in context based on price spikes experienced in 2016.

Table 5 below provides an estimate of the likely revenue loss to fast start generators of missing an isolated 5 minute electricity price spike due to their physical limitations in responding from cold start based on 2016 calendar year price outcomes. For example, the loss of revenue for generators in SA and QLD were $6.7 and $6 M respectively

Marsden Jacob has estimated that fast start generators in the NEM may face an overall reduction in revenue of $197 M per annum (assumes that fast start generators cannot predict the one-off price spike). It is noted that in the 2016 calendar year period selected, that there were relatively few prices spikes in NSW and Victoria compared with other regions.

Table 5: Revenue Loss associated with Missing Price Spikes (2016 Calendar Year)

Region	No. of DIs >$1000/MWh	Average Price ($/MWh)	High Price in Same 30 min Trading Interval (%)	High Prices that are Contiguous (%) (a)
NSW	25	6,280	96%	84%
QLD	100	8,262	10%	13%
SA	178	9,017	54%	49%
TAS	22	4,812	9%	23%
VIC	12	12,526	67%	67%

Region	High Prices that are isolated (No.)	Generator Size (MW)	Cost to Generator ($/year) of missing price spikes	Total Capacity of Fast Start Gen (MW) missing price spike
NSW	4	100	$209,350	984
QLD	87	100	$5,990,253	1842
SA	90	100	$6,762,821	1102
TAS	17	100	$681,707	205
VIC	4	100	$417,538	2090

Notes: (a) That is, high prices that occur in 2 or more sequential 5 minute dispatch intervals (DIs).

Source: Marsden Jacob analysis based on AEMO data

This reduction in revenue reflects the increased risk of providing cap contracts and is the reason why such generators would reduce the volume of such contracts,

It should be pointed out that in some jurisdictions and over the 2016 period reviewed, high price events are clustered, that is, they occur in the same trading interval or are contiguous (e.g. NSW and VIC). However, in QLD, SA and TAS, the majority of 5 minute price peaks are isolated and likely to be unpredictable. This implies they have a no probability of being captured by fast start generators operating in the NEM today. It is noted that other price data presented (refer reports provided by Energy Edge and Russ Skelton and Associates) over different time periods also supports that 5 minute electricity price spikes occur in a relatively isolated and unpredictable manner.

6.3 Energy Edge assessment of impact on cap volumes

The assessment of the impact of 5 minute pricing in cap contract volumes is very different from than that presented in the report by Energy Edge.

Based on theoretical and ideal technical responses, Section 4.6 of the Energy Edge report assesses that a reduced volume of caps that are likely to be sold or available under the proposed 5 minute financial settlement regime is in the order of 625 MW. The caps sold reduction percentage (by region) calculated by Energy Edge is shown in the table below.

Table 6: Energy Edge modelled reduction in volume of caps by generator type

Generator Type	Reduction in Theoretical Volume of Caps Sold (%)
Hydro (Conventional)	-18.2%
Hydro (Pumped Storage)	-46.4%
Liquids	-24.0%
Natural Gas (CCGT)	-7.8%
Natural Gas (OCGT)	-26.0%
Natural Gas (Steam)	-29.1%

Table 6 - Modelled reduction in volume of caps by generator type

Source: Energy Edge, Table 6, page 59

Based on the observed technical characteristics of peaking plant operating in the NEM, the analysis presented in this report and the practical consideration of being able to forecast and respond to high 5 minute pool prices, Marsden Jacob considers that the reduction in volumes suggested by Energy Edge is extremely conservative.

Energy Edge acknowledges that the vertically integrated players, who use peaking plant to manage their retail load, will also be materially impacted by the change to 5 minute financial settlement, but that this volume is not included in the 625 MW amount quoted and used in the report and accordingly referenced by the AEMC:

> *"the net impact on Cap supply will be much larger than the 625 MW per table 7, potentially to the equivalent of 23% of cap like generation capacity held within vertically integrated corporations".*

6.4 Changed cap volume requirements and vertical integration

We lastly address the impact of Vertical Integration on contract availability.

The extent of vertical integration in the NEM regions is considerable and cannot be ignored by the AEMC in calculating the overall impact in the NEM in relation to impacted contract volumes of a proposed change to 5 minute settlements. The extent of vertical integration is discussed further below.[20]

NSW

- Origin Energy and EnergyAustralia have 68 per cent of retail electricity customers and control 37 per cent of generation capacity;
- Snowy Hydro has 22 per cent of generation capacity and 4 per cent of retail electricity customers.

VIC

- AGL Energy, Origin Energy and EnergyAustralia each supplying 20–25 per cent of retail electricity customers (~70 per cent). The three major retailers control 54 per cent of generation capacity;
- GDF Suez (24 per cent of generation capacity) and Snowy Hydro (20 per cent) also have market shares of 8 per cent and 16 per cent of customers respectively.

SA

- AGL Energy supplies 50 per cent of retail customers and controls 42 per cent of generation capacity.

Other States (QLD and TAS)

- Vertical integration is less evident in Queensland and Tasmania, with a majority of generation capacity in each state controlled by state owned corporations.

Based on the significant and increasing degree of vertical integration in the NEM regions of VIC, NSW and SA, many of vertically integrated players have or control extensive peaking capacity that will be impacted by this proposed change to five minute financial settlement. While a number of these participants may also sell caps to external parties, this peaking plant has been historically used to manage extreme load and price in relation to their own retail position. Marsden Jacob's indicative analysis that the reduction in the amount of internal caps provided will reduce by at least another 3600 MW, in addition to the amount calculated by Energy Edge (see Table 4). Taking the impact of vertical integration into account with the externally traded cap contract volumes indicated by Energy Edge, would indicate a magnitude well in excess of 4200 MW of NEM cap contracts that will still be wanted by retailers and customers but needing to be supplied from other sources.

6.4.1 Impact on Spot and Hedging Markets

The reduction in cap revenue, which is used to cover the fixed costs of OCGT and risk for other peaking plant in the NEM, will result in peaking plant bidding higher prices in the spot market to recover these fixed plant costs and risks. This cost increase will also be reflected in the value of hedging instruments (e.g. contract for differences, peak and off peak blocks etc.).

[20] https://www.aer.gov.au/publications/state-of-the-energy-market-reports/state-of-the-energy-market-2015

7. Battery Economics and System Operation

The introduction of 5 minute energy settlement has been stated as contingent on technologies entering that can provide the required response.

This chapter review the economics of batteries and the impact to system operators if this technology does not enter to the level necessary under 5 minute pricing.

7.1 Economics Battery Storage

As outlined in Section 3.2.3, the response rate of battery storage (in particular lithium ion) makes them a suitable option to provide fast start services in the NEM and the only technology that can respond to 5 minute prices. This technology can respond within microseconds to market signals and enable them to provide fast start services in the NEM (e.g. peaking energy and/or FCAS).

As noted previously, exceeding the linear ramp profile in a 5 minute period would, under current arrangements, require additional FCAS.

However, the cost of this technology is very high at the current time and the commercial justification for investment in lithium ion battery storage would require this technology earning a number of income streams. That includes: energy arbitrage, FCAS, network support services, network demand reduction, and relieving network constraints for intermittent generators in the NEM (LGC benefit).

Even with all of these income streams the current cost and lifetime of batteries far exceeds the potential return (see subsequent analysis).

To provide an indicative assessment of current battery economics, Marsden Jacob assessed the net benefits of installing lithium ion storage in the North West of Victoria, with the benefits including energy arbitrage, FCAS provision and reduction in network constraints.

The basis for this assessment included the following key assumptions:

- Battery size 25/50 (MW/MWh) lithium ion battery – discharge/recharge in 2 hours;
- Lithium ion battery cost - $620/kWh (installed);
- Inverter cost - $280/kW;
- Establishment costs of $4 M assuming that the battery shared a network connection with an intermittent generator;
- Loss of battery retention overtime (falls to around 66 per cent after 20 years of use);
- Discount rate 6.6% real;
- Lifetime 20 years.

The net financial benefits are presented Table 7 as a 20 year NPV. The assessment illustrates that currently this technology is not economically viable without subsidy.

However, there are likely to be significant cost reductions in lithium ion battery capital costs in subsequent years. Table 8 below presents the assessed economics of the above sized battery in the years 2017, 2021 and 2025 based on the following:

- Lithium ion battery costs reduce to $425/MWh in 2021 and $350/MWh in 2025;

- NPV of the network benefits in the range $0M to $10M ($10M being the midpoint of maximum reduced network demand and network constraint benefits shown in Table 7).

Table 7: Assessed NPV of 50 MWh battery in Victoria –2017 installed costs $M

Elements	
Energy Arbitrage	$10M
Reduction in Network Demand	Unknown: Could be up to $10M
Managing Network Constraints	Unknown: Could be up to $10M
FCAS Revenue	$10M
Total Revenue	**$20M** + potential network value
Battery O&M Costs	$3.5M
Total Capital Cost	$60M
Total Costs	**$63.5M**
Margin	**($43.5M) plus any network value**

Source: MJA analysis

Table 8: Net Benefits of Utility Battery Storage - Network Benefits NPV assumed from $0M to $10M

Year	2017	2021	2025
NPV Margin	($43.5M) to ($33.5M)	($29M) to ($19M)	($23.5M) to ($13.5M)

***Source*:** MJA analysis

Based on the very substantial cost reduction assumed and the ability to capture network benefits, battery storage will still not be viable (possibly co-located with large-scale intermittent plant) in Victoria by 2025, and mostly likely post 2030.

Here we note that the benefits of battery storage appear highly dependent on capturing the benefits of network cost reductions (kVA demand reductions) and relieving network constraints (to permit intermittent generators to increase sent out generation – which are specific to a region and difficult to quantify).

The business case for battery storage co-located with renewable energy plant will be improved in those NEM regions with higher price spreads than in Victoria (peak and off peak prices), a higher number of price spikes (e.g. both QLD and SA have higher numbers of price spikes) and/or increased network congestion.

Our analysis of the economics of battery storage, co-located with an intermittent generator, in both QLD and SA indicates that they may become feasible prior to 2025. However, there is significant uncertainty associated with capturing network benefits (e.g. relieving congestion and reducing peak network demand) in these regions, implying that the feasibility of battery storage in these states could range from the early 2020's to beyond 2025.

The viability of battery storage (co-located with generators) is highly dependent on which region the investment is made. Even with aggressive assumptions regarding large reductions in capital costs, battery storage is not likely to be economic until after 2025 in most NEM regions (i.e. NSW, VIC and TAS). Thus a move to 5 minute settlement is not likely to result in significant investment in battery storage in these states in order to improve a market participant's response rate to 5 minute price signals. In these cases, it is much more likely that existing plant (OCGT) will remain operating in order to capture future price spikes.

7.1.1 Battery co Located with a peaking plant

Alternatively, battery storage could also be co-located with peaking plant in the NEM so that they do not miss out on the financial benefit of 5 minute price spikes. This represents a significant cost increase for peaking plant, but an investment that may result in additional revenue.

Assuming that battery storage can be used to at least enable an OCGT to supply at minimum generation levels (around 40 per cent of total plant capacity) until the plant meets minimum generation levels (usually around 10-12 minutes).

Based on our analysis, investment in a 40 / 40 (MW/MWh) battery (excluding operating costs and replacement of the inverter after 10 years) has a benefit cost ratio of between 43 to 48 per cent in the NEM regions with the most frequent price spikes (QLD and SA). For the viability to be improved, other benefits would need to be factored into the analysis (e.g. relieving network congestion). However, given the current costs of this technology, it is not likely to be viable to co-locate battery storage with OCGT plant until at least 2025.

Table 9: Viability of Co-locating battery storage with an OCGT (100 MW capacity),

Battery Economics	2017
Installed Capacity (MW)	40
Effective Peak Capacity (MW) (a)	32.3
Unit Capital Cost ($/kW)	$1,000
Annual Capital Cost	$4.5M
Price Spike Benefit	
QLD	$1,9 M
SA	$2.1M

Notes: (a) Battery storage systems cannot export power at their nameplate or installed capacity because of round-trip efficiency losses (15 per cent) and that the depth of discharge for the battery is limited to 95 per cent.

Source: MJA analysis.

What this analysis suggests is that the likely response by owners of existing OCGT plant to 5 minute settlement will face significantly increased costs and risks which will be passed through to the spot marker or customers. Peaking generation will need to be run longer at minimum generation levels or investigate alternative capability such as fast start (if feasible). The costs of plant running at minimum generation is discussed in Section 7.2 (below).

7.2 Changed Generation Operation

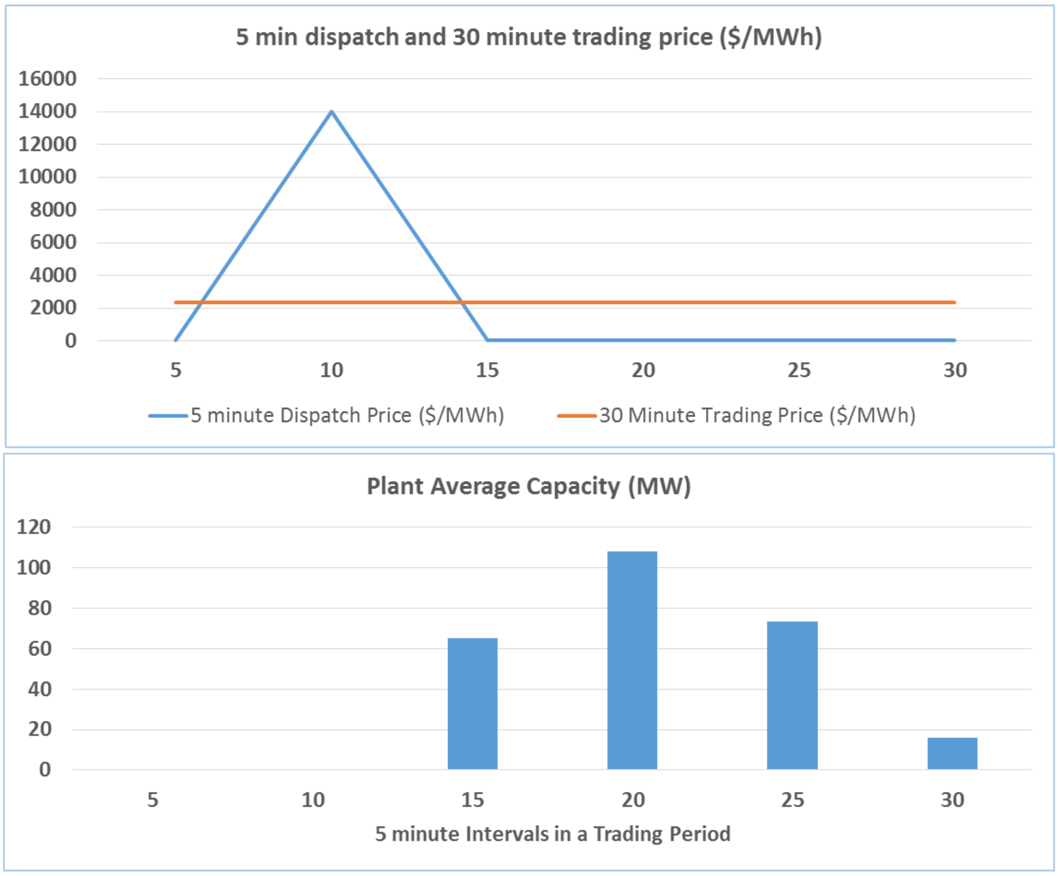
The alternative to installing batteries to capture 5 minute prices is to change the operation of existing generation. This is examined in this section.

7.2.1 5 Minute and 30 Minute Analysis

As outlined above, it is not economic for OCGT plant to install battery storage to improve response rates to 5 minute price spikes. As a result, it is likely that OCGT plant will operate at minimum generation levels to ensure that they don't miss out on the revenue from 5 minute price spikes. This analysis is confirmed below.

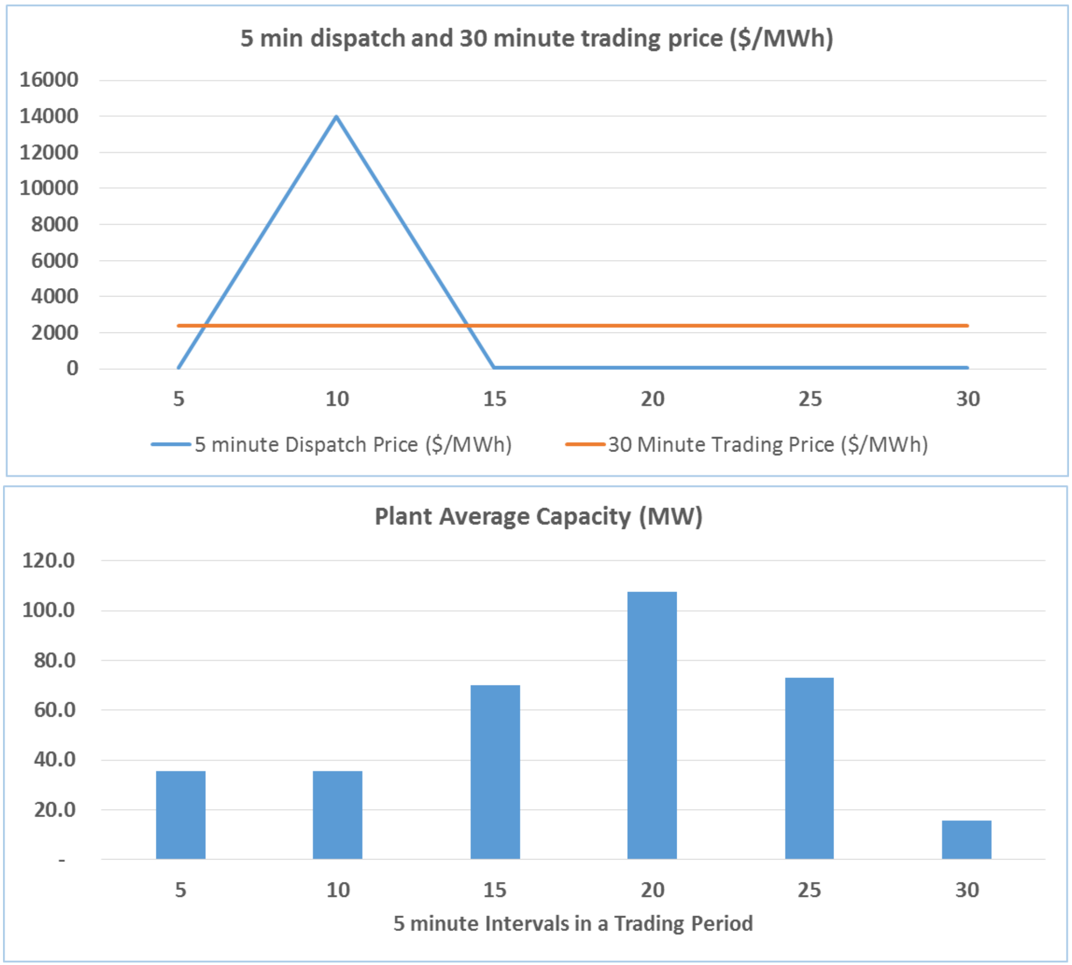
This shows the response rate of a typical OCGT plant in the NEM to a 5 minute price spike ($14,000 per MWh in the second 5 minute period, with a 5 minute spot price of $40 per MWh in all other 5 minute periods). Although the plant misses the 5 minute price spike, it is able to benefit from the 5 minute price spike by operating in the remaining period of the 30 minute trading interval (assuming 30 minute settlement). The 30 minute trading price is $2,367 per MWh and the OCGT earns $51,769 for the trading period. Under 5 minute settlement, the OCGT plant would only earn $875 for the 30 minute period.

Figure 9: Generator response by 100 MW OCGT Plant – Ramping up from Cold Start



With 5 minute settlement, an operator of OCGT plant will likely keep the plant operating at minimum generation levels if there is a significant likelihood of a price spike (e.g. spot price > $1000 per MWh). This is an inefficient mode of operation compared with running the unit at full load, but is necessary to enable the plant a higher probability of capturing a five minute price spike due to its technical characteristics (e.g. ramp rates). Price spikes in the NEM usually result from the failure of generation plant, failure to forecast scheduled demand accurately, transmission equipment and limitations on the interconnectors (i.e. especially in SA). To manage potential price volatility peaking generators may keep the plant operating at mingen when these circumstances arise in their region. In this case, when the price spike occurs in the second dispatch interval, the plant is able to benefit at the minimum generation level and then ramps up to or near maximum capacity (achieved in the fourth trading interval) – refer figure below.

Figure 10: Generator response by 100 MW OCGT Plant - Ramping from Minimum Generation



The revenue benefit for the OCGT plant is $42,422 in the trading interval if it remains at the mingen level. In our analysis, we have assumed that the OCGT plant must remain on for a minimum of 6 hours in order to capture the benefits of the price spike (given the relative randomness of price spikes even with infrastructure failures), which implies a running cost of $27,690 – a net profit of $14,731 (see following table).

Table 10: Net Benefits of OCGT Generation in Response to Price Spikes

Scenario	Response from Cold Start	Response from MinGen
Revenue for OCGT ($)		
5 minute Settlement Period	$875	$42,422
30 minute Settlement Period	$51,769	$66,464
Revenue loss from 5 minute settlement	$50,894	$24,042
Costs Incurred for OCGT ($)		
5 minute Settlement Period	$2,110	$27,690
30 minute Settlement Period	$2,110	$27,690
Net Benefit ($)		
5 minute Settlement Period	$(1,235)	$14,731
30 minute Settlement Period	$49,659	$38,774

While the OCGT plant benefits by operating at mingen, dispatch costs in the market are increased overall. If we assume that the plant, which should not be operating and bids into the market to remain at mingen, operates 6 hours to capture each price spike (assume eighty 5 minute price spikes per year), then the additional market cost for the plant (108 MW) operating out of merit order is $1.6 M per annum. If we assume that 4000 MW of plant in the NEM behaves in this way, the extra market costs of out of merit dispatch would be $60 M. In our analysis it is assumed that OCGT plant (with a heat rate of 14 GJ/MWh) displaces a more efficient gas plant with lower heat rate (10 GJ/MWh). These extra market costs will be paid for by customers.

The implications of the reduced margins for OCGT and other peaking plant is that cap prices will have to increase in order to enable operators of this plant to recover the risk and fixed cost of the plant in a five minute pricing environment. In our example above, the reduction in net margins for an OCGT plant is around 29.67 per cent (refer above table). In order for that peaking plant to recover that revenue and still provide the same level of caps, they will need to at least offer cap prices at close to 30 per cent above current levels. Given an average cap price across the NEM of $13.06/MWh, a 30 per cent increase in cap prices across the NEM (assuming 4000 MW of caps are offered in NEM regions) is $137 M.

7.3 Impact of 5 minute settlement on FCAS Costs

As highlighted above and in Section 2.3 (Impact of FCAS), 5 minute energy settlement could result in more generation capacity being reserved for the energy market, which would reduce the amount of capacity available to provide FCAS raise services. There is also likely to be an increase in the amount of FCAS lower service capacity offered in the market (more plant operating with the ability to reduce generation).

Further, there would likely be increased disorder within each 5-minute period due to non-scheduled generation (e.g. behind the meter technologies such as diesel generators and batteries) and demand side facilities (e.g. oil refineries and aluminium smelters) that aren't centrally dispatched responding to 5 minute price signals. This has the potential to increase the amount of FCAS required for frequency control.

Marsden Jacob estimates that the implementation of 5 minute settlement could result in FCAS costs increasing in the order of $15M to $30M per annum (noting the significant uncertainties in this estimate). We also note that reform in the non-scheduled market and ancillary services markets would impact these costs.

7.4 Consequences of Changed Generation Dispatch

As outlined above, it is likely that OCGT plant (running on gas) will increase their operations in order to benefit from 5 minute price spikes under 5 minute settlement. In addition, generation operators may also increase the part loading of coal fired units so that more units can operate and respond to 5 minute price spikes.

The implications of the increased operation of OCGT plant, and increased part loading of coal plant, include the following:

- Increased part-loading of generation plant in the NEM, with a consequent net increase in the heat rates of plant (both coal and gas). This could increase fuel costs and overall gas and coal use in the NEM.

- The increased gas demand for power generation will put further price pressure on the East Coast Gas Market until new (cheaper) coal supplies are developed (e.g. coal seam methane in NSW or Victoria, or increased supplies from the Northern Territory (expansion of the Northern Gas Pipeline).
- Emission intensity (tonnes per MWh) are likely to increase due to the increased part loading of both gas and coal plant in the NEM.

7.5 Impact on Customers

As outlined in Section 1.2, a key issue from a consumer perspective is whether the rule change will result in a rise in prices to final electricity customers.

Based on our review of the available evidence it appears that there is material risk that 5 minute settlement will increase costs to consumers. This is not to say that all consumers will experience a price rise; a certain cohort of customers may benefit (e.g. those providing curtailable load).

However, the fact that one customer (or category of customer) is likely to benefit from lower electricity supply costs does not mean that all will. The proposed rule change has the following consequences:

- It is expected to further increase infrastructure investment (such as battery storage and other peaking supply) and supporting services, when there is already considerable investment responding to the Commonwealth Government’s Large-scale renewable energy target (LRET); and
- Decrease the utilisation of existing generation (peaking) infrastructure since they may not be able to respond to 5-minute price signals in a cost-effective manner.

Based on Marsden Jacob’s analysis of the available information, our professional opinion is that there is a material risk that this rule change would result in price increases to consumers. To properly assess the impact before any decision is taken on this rule change, it is essential that both economic (cost-benefit analysis) and a price impact assessment is undertaken both in aggregated and from a distributional perspective to check whether the proposed change is improving outcomes for final customers.

In other words, the key question is whether addressing the identified perverse incentives (such as late rebidding, non-conformance and inflexibility of supply) with 30-minute settlement through implementation of 5-minute settlement will result in lower prices for consumers. Based on our review of the new incentives that emerge under the current arrangement relating to both existing and potential infrastructure, Marsden Jacob is concerned that the current analysis has not demonstrated that the cost of electricity supply will reduce across both individual customer segments and across the overall customer base.

8. Broader Implications

In considering the proposed rule change, it is also important to understand how this proposed rule change (5 minute settlement) may impact, or be impacted by, a range of other relevant rule changes that effect the generation dispatch process.

8.1 Other relevant rule changes impacting on the 5 minute settlement rule change

In addition to the 5-minute settlement rule change, a wide range of other rule changes have and will impact the NEM dispatch process. A summary of these rule changes include the following:

- A change to the good faith rebidding provisions of the rules[21]. This change, which was made on 10 December 2015, came into force on 1 July 2016. This now requires participants to *"not make an offer, bid or rebid that is false misleading or is likely to mislead"* and to require participants who make a rebid during or less than 15-minutes before the trading interval to "*make a contemporaneous record in relation to the rebid"*. It would appear that this implemented rule change has already reduced the incidence of price spikes in dispatch intervals 5 and 6 (in a 30 minute trading interval), therefore lessening the justification for using 5 minute settlement to incentivise rapid response generation to come on line to lower prices in the last 10-15 minutes of a trading period;
- A rule change submitted by Snowy Hydro[22] seeking market loads greater than 30 MW, which are or intend to be price responsive, to be registered as scheduled loads and being required to submit bids and follow dispatch instructions. This would assist AEMO to better forecast demand and supply and should result in less unexpected price spikes that can result from incorrect generation supply forecasts;
- Rule change submitted by ENGIE[23] seeking to include non-scheduled generating units between 5-30 MW in the central dispatch process;
- Rule change submitted by AGL[24] seeking the introduction of a NEM-wide Inertia Ancillary Services market – which would compensate some generators to remain at minimum generation so that they can ramp up rapidly to meet changes in either demand or supply;
- A package of rule changes proposed by the South Australian Government[25] to make rule changes so that *"the regulatory framework supports competitive and efficient provision of ancillary services necessary to manage emerging security challenges such as high rate of change of frequency"*

All of these rule changes are likely to have a considerable impact on the efficiency of the dispatch process and it would be appropriate for the AEMC to consider their impact as part of

21 *AEMC Final Rule Determination - http://www.aemc.gov.au/getattachment/815f277c-a015-47d0-bc13-ce3d5faaf96d/Final-Determination.aspx*

22 *Snowy Hydro - rule change request - http://www.aemc.gov.au/getattachment/0b9688b8-dc3c-49b1-8bf8-df587ca8ed53/Rule-change-request.aspx*

23 *GDF Suez (now Engie) – rule change request - http://www.aemc.gov.au/getattachment/4219ffd9-f0f1-4690-84a8-555282d44374/Rule-change-request.aspx*

24 *AGL – rule change request - http://www.aemc.gov.au/getattachment/bacba344-8989-4107-ae2a-480427c9c9f9/Rulechange-request.aspx*

25 *SA Government rule change request - http://www.aemc.gov.au/getattachment/cd295d50-46a0-4c1e-a988-2453ebc07f0c/Rule-change-request.aspx*

an overall package of rule changes as part of assessing the proposed 5-minute settlement rule change. It is entirely possible that the impacts of one of these rule changes (such as the already implemented good faith rebidding rule) may impact on other rule changes, which means that the benefit of one rule change may be additional or else negated by another rule change. For example, without implementing the non-scheduled load and generation rule change, the difficulty for scheduled plant under 5-minute energy settlement will be made worse, thereby accelerating their early exit from the NEM. It is therefore considered imperative that the AEMC considers this proposed rule change as part of an overall package of potential rule changes.

8.2 Other market settings/issues

8.2.1 System Reliability Review and market settings

The AEMC, through the Reliability Panel, is also going to embark on a major review of system reliability. Under the National Electricity Rules, the Reliability Panel is required to carry out a review of the reliability standard and reliability settings every four years. This regular review allows the Panel to consider whether the reliability standard and reliability settings remain suitable, or whether changes should be made to ensure these mechanisms continue to meet the requirements of the market, market participants and consumers.

It is noted that changes to the market operation and movement from 30 minute to five minute settlement over the time frame proposed by the AEMC will definitely impact on the operation of the NEM. It is Marsden Jacob's opinion that any change from 30 minute to five minutes settlement will have a considerable impact on the reliability settings of the NEM and warrant a major overhaul of the market price cap, cumulative price threshold and market floor price. While a great deal of modelling would need to be undertaken, in light of reduced revenue and risk that would be available for peaking generation under this proposed rule change there is a high probability that there may need to be a significant increase in the Market Price Cap.

If the reliability standard and settings are not reviewed, they may not continue to facilitate appropriate signals for investment and this would ultimately have a detrimental effect on the reliability of electricity supply to consumers. This review focuses on the reliability of the power system; specifically the reliability provided by the generation and interconnection assets. The Panel is to publish its report by 20 April 2018.

Purpose of the review

The review is to consider the reliability standard and settings to apply on and from 1 July 2020. The review is to:

- consider whether the existing reliability standard remains appropriate for the expected market conditions (note and this may or would need to reflect operation under a five minutes settlement regime if the proposed rule change was to proceed);
- if the Panel considers that the existing reliability standard is not appropriate for the expected market conditions from 1 July 2020, recommend a revised reliability standard that should apply from 1 July 2020 consider whether the existing reliability settings remain appropriate for the expected market conditions;
- if the Panel considers that the level of an existing reliability setting is not appropriate for expected market conditions from 1 July 2020, recommend the level appropriate to that reliability setting that should apply from 1 July 2020; and

- propose changes to the rules to implement any recommended changes arising from the review.

8.2.2 Other market issues

Pre-dispatch forecasts produced by AEMO are already adversely impacted by the operation of non-scheduled generation and load. Under 5 minute settlement, this problem could worsen as scheduled dispatch will have to respond in even shorter timeframes. It is therefore likely, despite the best intentions from AEMO, that pre-dispatch load and price forecasts will become less reliable, with further adverse consequences for scheduled plant attempting to optimise their operations.

The requirement and cost of FCAS are also likely to increase further as more intermittent generation is brought-on-line. Relevant to this rule change is the fair allocation of FCAS costs to users. With greater uncertainty and likely increased short term response, unscheduled plant could increase their generation level (or unscheduled loads reducing their demand), requiring higher amounts of contingency lower ancillary services to return the system to normal operating limits. Under current rules, the generator (or load) do not pay a fair contribution towards these higher costs.

As a result of the 5 minute settlement rule change, we also note some potential and significant changes being considered by the AEMC to the treatment of settlement residues (refer Section 5.3.3 of Directions Paper). This would appear to introduce considerable new cost and complexity to the market design without any perceivable or quantified benefits.

Appendix 1: Supply Side Technologies

In this Appendix, we summarise the performance (and in particular the response rate) of existing generation technologies and new technologies that could be deployed in the future to provide an efficient response to 5 minute price signals.

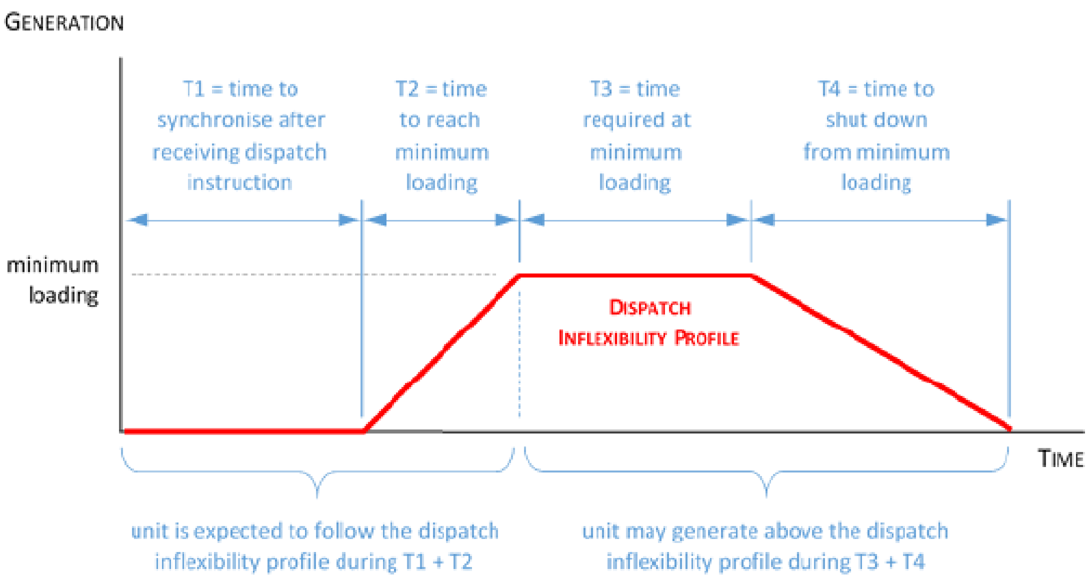
A.1 Existing generation technologies in the NEM

The ability of generation plant to respond to 5 minute price signals is dependent on two factors:

- Time from rest (or cold start) to synchronise and ramp to minimum loading – defined by dispatch inflexibility profiles for fast start generators;
- Rate of change in output after minimum loading or when they are already operating (i.e. ramp rates, minimum and maximum loading)

Fast start generators[26] have a defined dispatch inflexibility profile and is illustrated below.

Figure 11: Fast start inflexibility profile - indicative



where

T1, T2, T3, T4 ≥ 0

T1 + T2 ≤ 30 minutes

T1 + T2 + T3 + T4 < 60 minutes

T1, T2, T3, T4 are all measured in minutes

The ability of fast start generators to respond from cold start to minimum loading (T1 to T2) is shown for OCGT and hydro plant in the NEM on average (which also provide $300/MWh caps in the NEM). What this shows is that both Hydro stations and OCGT units take (on average)

26 Is a unit that can synchronise and reach its minimum loading within 30 minutes, and can synchronise, reach minimum loading, and shut down in less than 60 minutes

4.1 and 15 minutes respectively to achieve minimum generation levels ('mingen') before they can ramp up to full capacity to take full advantage of price spikes within the trading interval.

Table 11: Generator response times by Generator Technology (minutes)

Technology	Min Load (MW)	T1	T2	T3	T4
Hydro	16.0	2.8	1.3	6.9	1.1
OCGT	45.8	10.1	4.6	25.8	3.5

Source: AEMO data

Table 11 (below) shows the aggregated T1 and T2 times (cold start to Mingen) and the ramp rate after Mingen for different plant types in the NEM. A hydro plant is able to ramp to 78 MW in a minute, whilst an OCGT plant can ramp 20 MW in one minute. This highlights that once a plant is operational, the plant can very quickly ramp up to full capacity to take advantage of a price spike.

Table 12: Response rates of change by technology

Technology	Maximum Capacity (MW)	MinGen (MW)	Average of Max ROC (MW/Min)	Time from Cold Start to MinGen (Min)	Time from Cold Start to Maximum Capacity (Min)
CCGT	297	98	35	18.0	23.6
Coal - Steam (a)	502	125	10	varies	varies
Gas - Steam (a)	300	75	20	120.0	131.3
Hydro - Gravity	231	51	78	5.0	7.3
Hydro - pumped storage	271	138	70	2.5	4.4
Hydro – River	26	13	5	6.0	8.7
OCGT	108	43	20	10.0	13.3
Reciprocating Engine	50	48	14	5.0	5.1

Source: AEMO Registration data

The implications of the physical characteristics of Hydro and OCGT plant are discussed below:

- From cold start to maximum capacity for a typical Hydro or OCGT, this can take up to 9 minutes for hydro plant and around 13 minutes for OCGT plant. This implies that both Hydro and OCGT plant could miss out (at least partially) on peak price events that occurs in the first two 5-minute periods in a trading interval for Hydro plant, and the first three trading intervals for an OCGT plant. OCGT plant may not be able to take full advantage in later periods of the 30 minute trading interval since they cannot get to maximum capacity until the end of the trading interval.
- OCGT and hydro units have relatively high ramp rates once operating at minimum load. This implies that this plant may bid low prices (below operating costs) to remain on (i.e. could provide FCAS) so that they can participate in high price events (when the likelihood is high). This could result in *"out of merit order"* dispatch in the spot market which can result in higher costs than otherwise.

To overcome the problems of missing out of peak price events, existing fast-start generators can undertake measures to reduce the synchronisation time and/or increase ramping capability to respond to 5-minute price signals. For example, some gas peaking plant can be configured to bypass some stages of the start-up process before energy is provided to the grid and synchronise more rapidly (within 2 minutes). However this normally results in additional (sometimes triple) wear and tear (and associated cost) of a normal unit start.

A.2 Fast start generation technologies

Some gas technologies and diesel generators are capable of providing a very fast response, both in terms of time to synchronise and time to ramp up.

This is highlighted in the table below for conventional OCGT, aero-derivative gas turbines, reciprocating and diesel engines of between 150 to 160 MW in capacity.

Table 13: Fast Start Generation Technologies (~160 MW)

Generation Type	Open Cycle Gas Turbine	Aero-Derivative (OCGT)	Reciprocating Gas Engine	Reciprocating Diesel Engine
Unit Size	166	150	160	160
Minimum Generation	80	45	-	-
Fast-start inflexibility profile (min)				
T1	6	2.8	1	2.5
T2	7.0	5.2	2	1.2
T3	39	29	6	6.9
T4	7	5	1	1
Unit Ramp Rate (MW/min)	10	8	20	20
Time from cold start to Full Load (min)	29.60	26.75	11.00	11.70

Source: MJA

A.3 Battery storage

Battery storage technologies

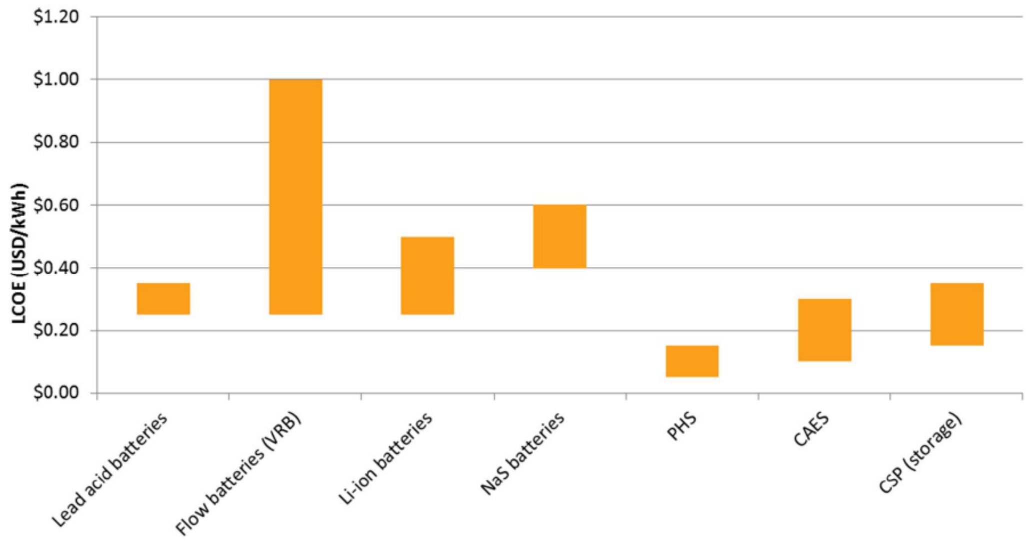
Lead-acid batteries are the most commonly used type of rechargeable battery. They are low cost and are used in numerous applications including vehicles, off-grid power systems and uninterruptible power supplies. Typical lead-acid batteries have efficiencies of around 70-90 per cent with an expected lifetime of 5-15 years. They typically have lower cycle lifetimes and depths of discharge than other battery types.

Lead-acid batteries have been coupled with numerous solar, wind and off-grid power systems. However, the declining costs of lithium-ion batteries and better operating performance (i.e. depth of discharge and efficiency) when compared to lead-acid has seen these technologies displaced by lead-acid batteries in many applications.

Flow batteries (Zinc Bromine and Vanadium Redox) are scalable batteries that are also useful for large-scale intermittent plant. Flow batteries are usually between 65 and 80 per cent efficient, permit up to 10,000 cycles, allow operational flexibility in terms of depth-of-discharge, and have a short response time.

On a levelised cost basis, lithium ion batteries are significantly lower cost than flow batteries.

Figure 12: Levelised costs of battery technologies



Source: AECOM, *Energy Storage Study, Funding and Knowledge Sharing Priorities,* Prepared for ARENA, July 2015

Based on the current costs and scalability of lithium ion batteries, our paper concentrates on the operating performance (and costs) of this technology in helping to understand future outcomes in the NEM with 5 minute settlement.

Battery (Li-ion) Operating Performance and Costs

The basic configuration of a battery storage system is summarised below.

- Lithium ion battery – 50 MWh (nameplate) required to time shift energy and to provide frequency control ancillary services (maintain frequency).
- Inverter capacity – 25 MW (nameplate).
- Battery management system – required to control energy released for energy, capacity and/or frequency control ancillary services.

The operational performance of the lithium ion battery technology is outlined below.

Table 14: Performance Characteristics of Lithium ion batteries

Technology	Units	Lithium-ion
Capacity	MWh	50
Depth of Discharge	per cent	95
Cycle life	no. of cycles	5,000
Lifetime	years	10
Round-trip efficiency	per cent	85
Typical charge time	hours	4
Typical dis-charge time	hours	2
Modelling temperature	degrees celsius	25

Source: MJA analysis and Brinsmead, T.S., Graham, P., Hayward, J., Ratnam, E.L., and Reedman, L. (2015). *Future Energy Storage Trends: An Assessment of the Economic Viability, Potential Uptake and Impacts of Electrical Energy Storage on the NEM 2015*–2035. CSIRO, Australia. Report No. EP155039.

The cost of Energy Storage Technologies are outlined below in AUD.

Table 15: Energy Storage Upfront Costs

Technology	Units	Cost
Lithium ion battery cost	AUD/kWh	570.0
Inverter Cost	AUD/kW	280.00
Other Establishment Costs (a)	AUD	4,000,000

Source: Magellan Power Quote

Notes: (a) assumes battery is co-located with a Generator. If not, other establishment costs will be $4 M higher. Includes cost of a battery management system, electrical costs (e.g. onsite transformers) and the costs of preparing the site. Additional electrical costs are incurred if the energy storage system is stand alone.

Based on the proposed capacity of batteries and inverters, the estimated upfront cost of the energy storage solution is $42 M (assumes co-located with a generator). Adjusting for energy efficiency losses and restrictions on depth of discharge, this implies an installed cost of $2,080/kW (effective capacity of 20.187 MW).

The estimated fixed and variable costs associated with the energy storage solution are shown below.

Table 16: Energy Storage O&M Costs

Operations and Maintenance Costs	Units	Lithium-ion
Fixed O&M	AUD/kW/annum	10
Variable O&M	AUD/kWh	0.0031

Source: *Brinsmead et al.*

Glossary

Abbreviations

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AGC	Automatic Generation Control
AUD	Australian dollar
CCGT	combined-cycle gas turbine
CPT	cumulative price threshold
FCAS	frequency control ancillary services
kW	kilowatt
kWh	kilowatt hour
MFP	market floor price
MJA	Marsden Jacob Associates
MNSP	market network service provider
MPC	maximum price cap
MW	megawatt
MWh	megawatt hour
NEL	National Electricity Law
NEM	national electricity market
NEMDE	National Electricity Market Dispatch
NER	National Electricity Rules
NYISO	New York Independent System Operator
OCGT	open cycle gas turbine
OTC	over-the-counter
SCADA	supervisory control and data acquisition
VoLL	value of lost load
WEM	Wholesale Electricity Market (WA)