Submission to the

Five Minute Settlement

consultation paper

Melbourne Energy Institute
June 2016

Introduction

The Melbourne Energy Institute welcomes the opportunity to provide comment on the Australian Energy Market Commission's *Five Minute Settlement, consultation paper*.

The Institute brings together the work of over 150 researchers, across seven faculties at The University of Melbourne , providing international leadership in energy research and delivering solutions to meet our future energy needs. By bringing together discipline-based research strengths and by engaging with stakeholders outside the University, the Institute offers the critical capacity to rethink the way we generate, deliver and use energy.

The Institute presents research opportunities in bioenergy, solar, wind, geothermal, nuclear, fuel cells and carbon capture and storage. It also engages in energy efficiency for urban planning, architecture, transport and distributed systems, and reliable energy transmission. Economic and policy questions constitute a significant plank of the Institutes research program and include: market regulation and demand; carbon trading; energy system modelling; climate change feed backs; and social justice implications of energy policy.

We broadly support the changes proposed by Sun Metals Pty Ltd (Sun Metals) with respect to aligning the dispatch and financial settlement intervals in the National Electricity Market. In this submission, we first highlight the importance of 'fast market', and argue the current arrangements 'hobble' efficient operation of the system. Section two discusses some of the perverse incentives created by the current arrangements.

We thank you for the opportunity to provide comment to this process and please do not hesitate to contact the Melbourne Energy Institute on 03 8344 3519.

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1 De-carbonisation & Electricity Market Design

In December 2015, a historic global climate agreement was agreed under the United Nations Framework Convention on Climate Change at the 21st Conference of the Parties in Paris. This agreement included a global goal to hold average temperature increase to well below 2 °C and pursue efforts to keep warming below 1.5 °C above pre-industrial levels. According to the IEA, the average CO_2 intensity of electricity needs to fall from 0.411 t/MWh in 2015 to 0.015 t/MWh by 2050 to achieve the goal[1].

As part of this agreement, Australia has committed reduce emissions to 26–28% of 2005 levels by 2030[2]. These targets are *'substantially weaker'* than those recommended by the Climate Change Authority in 2015[3], and may be strengthened over time. In addition, Australia's electricity sector has historically had a high emission intensity (0.8 t/MWh)[4], and is responsible for approximately a third of Australia's emissions. As such, the need to de-carbonise will necessarily have dramatic impacts on the electricity sector.

While many studies conclude that such a de-carbonisation is both technically and economically feasible, reaching this goal calls for careful consideration of market design[5]. Electricity market design has a significant impact on the efficient scheduling and operation of power systems. As penetrations of variable generation increase, market structure and generation scheduling rules become even more important to ensure efficient utilisation of the generation fleet. Importantly, most market design characteristics that facilitate the integration of of variable generation also improve the efficiency and operation of *without* variable generation[6].

The importance of 'fast markets' is particularly relevant for this consultation. Earlier this year, the International Energy Agency (IEA) released *'Re-powering Markets Market design and regulation during the transition to low-carbon power systems'*[7], the first official publication from the IEA that analyses the electricity market framework for low-carbon power systems. The IEA reports describes short term markets and increasing price resolution as 'pivotal'[8].

1.1 'Fast Markets'

Fast markets can be loosely defined as markets with short dispatch intervals (for example 5 minutes). The value of short dispatch intervals is described in *'Market Design for the Integration of Variable Renewables'*[9]:

> *Short dispatch intervals allow more frequent redispatch of the whole systems, enabling deviations to be dealt with by adjustment of every market participant in the system as appropriate. Long dispatch intervals mean that deviations in load and variable generation away from the central set point for the interval for be significantly larger, requiring larger regulation services*
>
> ***Reisz et al., 2013***

Similarly, a report prepared by the U.S. Department of Energy's National Renewable Energy Laboratory[10] emphasises the importance of fast energy markets. They argue that

[1] IEA, *Re-powering Markets*.
[2] Australian Government, *Fact sheet: Australia's 2030 climate change target*.
[3] Bernie Fraser, *Some observations on Autsralia's post 2020 emissions reduction target, statement by the chair*.
[4] Vivid Economics, *Analysis of electricity consumption, electricity generation emissions intensity and economy-wide emissions: Report prepared for the Climate Change Authority*.
[5] IEA, *Re-powering Markets*.
[6] Riesz, Gilmore, and Hindsberger, "Market Design for the Integration of Variable Generation".
[7] IEA, *Re-powering Markets*.
[8] See ibid., Chapter 3: 'Short-term markets', page 73.
[9] Riesz, Gilmore, and Hindsberger, "Market Design for the Integration of Variable Generation", page 764.
[10] Milligan and Kirby, *Market characteristics for efficient integration of variable generation in the Western Interconnection*.

short dispatch intervals and sub-hourly energy markets provide the right economic signals for conventional generators and flexible generators to respond to short term fluctuations in load and variable generation. Indeed this report strongly argues that long time resolution pricing increases costs and 'hobble's' the generation fleet:[11]

> *Scheduling rules that restrict generators to hourly movements artificially hobble the conventional generation fleet, resulting in lost opportunities for those generators and increased costs for all.*
>
> ***Milligan and Kirby, 2010***

The National Electricity Market (NEM) does make use of short (5 minute) dispatch intervals. However, the process of averaging the price over the trading interval (30 minutes) renders the 5 minute price signal impotent. The incentive to efficiently respond to the 'fast' dispatch market is muted. Participants are in effect incentivised to optimise operational decisions against the half-hourly prices, diminishing the value of having fast dispatch interval.

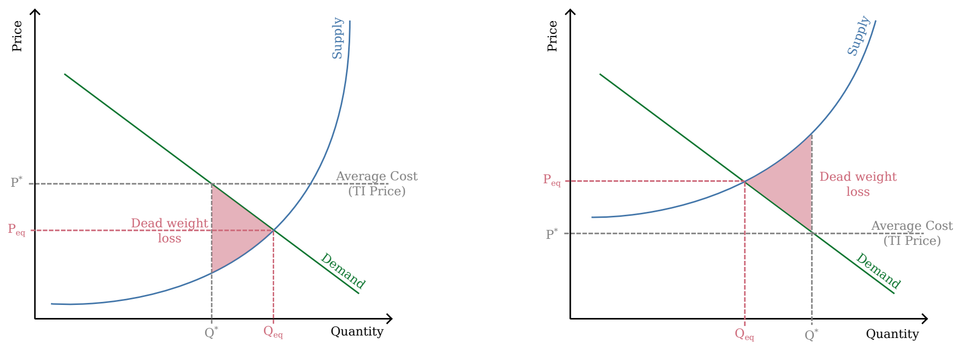
While the NEM does technically have sub-hourly (30 minute) trading intervals, the current process of averaging prices and 'hobbles' the generation fleet, by *not* providing the incentives and price signals of a 'fast market'. This creates sub-economic outcomes and perverse incentives (such as rebididing), which are discussed further in the following sections.

AEMO Specialist

It is worth noting that two of the authors of *'Market Design for the Integration of Variable Generation'*[12] are specialists at the Australian Energy Market Operator (AEMO). Dr Jenny Riesz is currently a Principal in Market Policy Development and Magnus Hindsberger a specialist in Modelling and Analytics, and Forecasting. Consultation with AEMO on this rule change would be highly valuable.

1.2 Allocative inefficiency of average pricing

The current arrangements result in two particular sub-economic outcomes. Firstly, where the marginal cost of supply (dispatch price) is *below* the average price (trading price), consumption and production is below the market equilibrium (scenario 1, figure 1a). Secondly, where the marginal cost of supply (dispatch price) is above than the average price (trading price) consumption and production is above the market equilibrium (scenario 2, figure 1b)



(a) Scenario 1 **(b) Scenario 2**

Figure 1: Allocative inefficiency resulting from current arrangements

Importantly, these sub-economic outcomes are not dependant on *when* the differences occur with in the interval, but only *if* there is a difference. A significant price spike in any one dispatch interval will result in a loss of welfare.

[11] Milligan and Kirby, *Market characteristics for efficient integration of variable generation in the Western Interconnection*, page 16.

[12] Riesz, Gilmore, and Hindsberger, "Market Design for the Integration of Variable Generation".

Arguably, the difference between dispatch prices and trading prise is relatively small most of the time. Table 1 below shows the distribution of maximum pricing differences for the mainland market regions. For example, 50% of the time, the maximum price difference between trading intervals and dispatch intervals is less than $2.10 in NSW, and less than 1% of time, the price difference is greater than $194.30 in SA.

However, due to the high price cap, the differences can very significant. Additionally, the settlement price for these trading intervals can be very high, and there proportion of market turnover that occurs in these trading intervals can be high. Table 2 below shows the proportion of market revenue that occurs in trading intervals with the price differences described in table 1. For example, while less than 1% of time, the price difference is greater than $194.30 in SA, those trading intervals represent almost 20% of the total turn over for the SA market in that year. For QLD, the proportion is as 29.63%, representing some $926 million[13].

This analysis is intended to highlight the contribution these intervals make to the overall turnover in the market. While these intra-interval spikes may have been efficient responses, the fact the prices are 'smeared' over a trading interval and that these trading intervals contribute disproportionately to annual turnover warrants further investigation, and suggest significant efficiencies cans be enabled.

Table 1: Distribution of price differences between trading and dispatch intervals, 2015

	Percentage of Trading Intervals			
	50%	**10%**	**5%**	**1%**
NSW	$2.10	$6.96	$11.00	$116.73
QLD	$2.34	$8.75	$27.18	$194.83
SA	$2.79	$11.52	$27.39	$194.30
VIC	$2.19	$8.85	$15.42	$100.91

Table 2: Proportion of market revenue in trading intervals with price differences

	Percentage of Trading Intervals			
	50%	**10%**	**5%**	**1%**
NSW	58.31%	22.66%	17.03%	7.23%
QLD	70.60%	45.50%	40.72%	29.63%
SA	64.82%	35.84%	29.58%	19.21%
VIC	58.56%	19.12%	13.42%	5.38%

[13] As discussed in section 4, some fraction of this is likely to be a function of rebidding practices

2 Perverse Incentives

Thirty minute settlement currently creates perverse incentives (or even disincentives) for flexible generation, such as open cycle gas turbines, pumped hydro, or battery technologies. In addition, it creates the conditions necessary for other market distortions, such as issues around 'rebidding'.

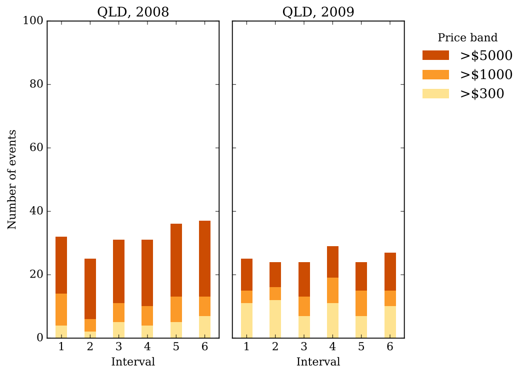
2.1 Rebidding

As noted by the Commission in the Bidding in Good Faith rule change *'the incentives on some generators to engage in strategic late rebidding were exacerbated by the mismatch between dispatch and settlement'*[14]. We argue that rebidding is largely an issue *because* of the mismatch between dispatch and settlement, and the ability to retrospectively impact prices. The incentive for late rebidding would be greatly reduced if the mismatch did not exist. In addition, the costs imposed by late rebidding are significant.

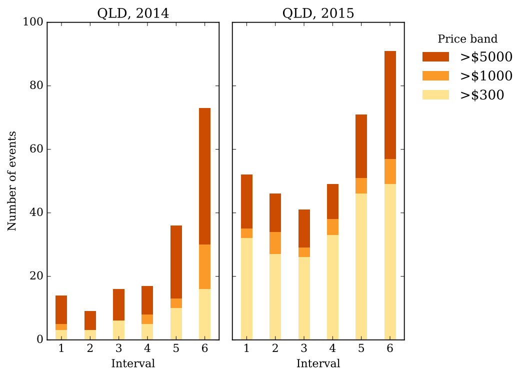
Figures 2a and 2b illustrate the distribution of price spikes in QLD in 2008-2009 and 2014-2015 respectively. As can be seen, the distribution of price spikes within a trading intervals is markedly different between these time periods. There is no logical reason that price spike should occur later in a trading interval: in theory they should be randomly distributed, as is seen in 2008 and 2009. Figure 2c further illustrates the evolution of the difference between the number of price spikes in the last interval relative to the number in the remaining intervals.

These spikes come at significant cost. Analysis of Queensland dispatch and settlement data suggest that in 2015, price spikes in the last 5 minutes of an interval added $250 million to the turnover through the wholesale market (see Appendix A, page 9 for further details).

The Bidding in Good faith rule changes, yet to come into effect, may *'lead to more efficient wholesale price outcomes'*[15]. However, it does not remove the fundamental mismatch that creates the incentives for this behaviour in the first place.



(a) Distribution of prices, 2008-2009



(b) Distribution of prices, 2014-2015

(c) Ratio of price events that occur in the last dispatch interval to events in remaining dispatch interval in QLD

Figure 2: Dispatch interval price spikes in QLD

[14]AEMC, *Five Minute Settlement: Consultation paper*, page 11.
[15]AEMC, *Bidding in Good Faith, Final Rule Determination*, page i.

2.2 Flexible generation incentives

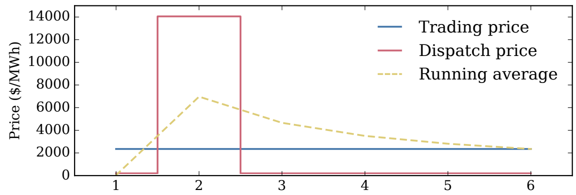
The following two examples illustrate how the current arrangements result in inefficient utilisation of generation capacity, and lead to under recovery of fixed costs and under create problems under typical hedging arrangements. These example assume a 30MW flexible generator with marginal costs of \$300/MWh, which has a perfect response. Whilst this is an idealised assumption, some technologies are highly responsive. Table 3 show Rate of Change possible (in MW/Min) by technology, based on the offers placed by generators in the NEM. Based on this data, A hydro plant would be able to ramp 30MW in 6 seconds, whilst an OCGT would be able to ramp 30MW in 18 seconds.

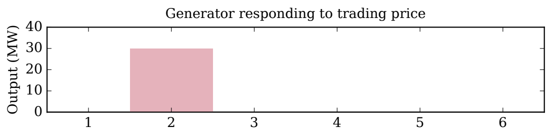
Table 3: Rate of Changes by technology, as offered to the NEM

	ROCUP (MW/Min)		ROCDOWN (MW/Min)	
Technology	**Maximum**	**Average**	**Maximum**	**Average**
Brown Coal	118	3.73	350	3.77
Black Coal	350	3.89	350	3.66
Gas (OCGT)	100	10.91	100	8.61
Gas (CCGT)	43	10.09	43	7.80
Gas (Steam)	57	6.23	50	5.32
Distillate	100	5.82	100	5.82
Hydro	300	31.81	200	24.15

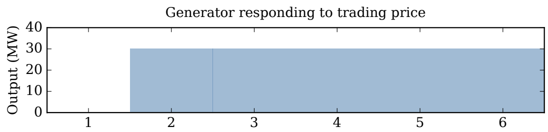
Inefficient utilisation

The following example illustrates the two different responses that would occur under the two different pricing regimes for a price spike occurring early in a trading interval. The 'running average' (yellow line) represents the average dispatch interval price at a given trading interval. .





	1	2	3	4	5	6
Dispatch price (\$/MWh)	40	13900	40	40	40	40
Output (MW)	0	30	0	0	0	0
Revenue (\$)	0	34000	0	0	0	0



	1	2	3	4	5	6
Trading price (\$/MWh)	2350	2350	2350	2350	2350	2350
Output (MW)	0	30	30	30	30	30
Revenue (\$)	0	5125	5125	5125	5125	5125

Figure 3: Optimal operation of generator under dispatch interval pricing and trading interval regimes

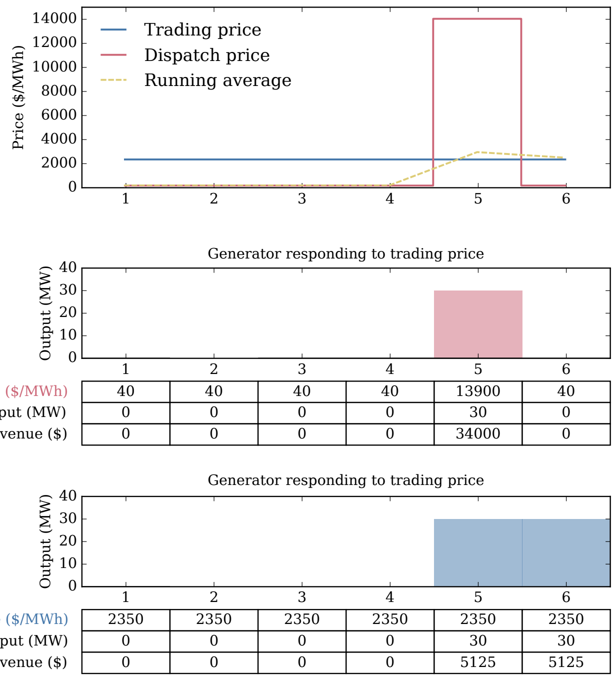
As illustrated in figure 3, the operating profiles are quite different. Once the price spike has occurred, it is rational for a generator (with margin costs of \$300/MWh) to continue generating for the remainder of the trading interval. This results in the generator incurring more costs than would be required in an efficient market. To cover fixed costs, the generator only recovers $25,650 relative to $34,000 in the case of a generator responding to the dispatch price.

Under recovery and contracting implications

The under recovery of fixed costs is best illustrated where a price spike occurs later in the interval (see figure 4). In this situation, the generator responding to the trading price, while over producing, only recovers $10,250. This is substantially less than the $34,000 recovered in the alternate case, and represents a significant risk for a flexible generator trying to recover fixed costs.

In addition, this has implications for how flexible generators (such as OCGT's) arrange finance and manage risks. Typically, such generators sell cap contracts[16]. In the situation presented figure 4, the generator would be liable to pay $30,750 to the cap contract counter party[17], presenting a significant risk and liability to the generator. This problem would not occur, should the trading price be hedged with a similar instrument.

In combination, these factors result in a barrier to entry or disincentive for fast response generators to participate in the market.



	1	2	3	4	5	6
Dispatch price ($/MWh)	40	40	40	40	13900	40
Output (MW)	0	0	0	0	30	0
Revenue ($)	0	0	0	0	34000	0

	1	2	3	4	5	6
Trading price ($/MWh)	2350	2350	2350	2350	2350	2350
Output (MW)	0	0	0	0	30	30
Revenue ($)	0	0	0	0	5125	5125

Figure 4: Optimal operation of generator under dispatch interval pricing and trading interval regimes

[16] See AEMC, *NEM financial market resilience: Issues Paper*, for more details on typical cap contract arrangements.

[17] Assuming a $300 cap contract

3 Conclusion

The current mismatch between settlement and dispatch:

- Diminishes the value of having fast dispatch
- Encourages sub-economic dispatch
- Does not provide appropriate incentives for fast response generation
- Creates opportunities for creative compliance (rebidding)

In summary, the Melbourne Energy Institute broadly supports aligning the dispatch and financial settlement intervals in the National Electricity Market.

References

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Appendix A

In this analysis, intervals with a price spike at the end of a trading interval in QLD were identified. Price a represents the trading interval price. Price b represents the average price in the first 4 trading intervals. The price difference and demand were used to determine the value of the end of interval price spikes.

Days or trading intervals with several price spikes were filtered out (for example, the 15th of January 2015 and the 5th of March 2015). Such days were assumed to reflect legitimate scarcity. A noteworthy pattern was high prices at 6:55am (trading interval 06), which several times throughout the year (and successive days in July).

Table 4: Intervals with price spikes in last dispatch interval

Trading Interval	Price a	Price b	Price Diff	Demand	Value (Million)
2015011306	\$4,543	\$65	\$4,478	6267	\$14.03
2015011432	\$2,392	\$238	\$2,153	7700	\$8.29
2015011522	\$2,291	\$140	\$2,151	8458	\$9.10
2015011624	\$2,522	\$33	\$2,489	8434	\$10.50
2015011625	\$2,231	\$34	\$2,197	8423	\$9.25
2015011626	\$4,523	\$35	\$4,488	8462	\$18.99
2015011627	\$2,272	\$24	\$2,248	8356	\$9.39
2015011726	\$2,209	\$64	\$2,145	8320	\$8.92
2015011832	\$2,270	\$115	\$2,155	8296	\$8.94
2015011834	\$2,579	\$578	\$2,001	7908	\$7.91
2015011909	\$2,367	\$167	\$2,201	7682	\$8.45
2015012626	\$2,278	\$32	\$2,246	7884	\$8.85
2015012628	\$2,274	\$29	\$2,245	7864	\$8.83
2015022426	\$2,325	\$105	\$2,221	7585	\$8.42
2015030306	\$2,370	\$105	\$2,265	6415	\$7.27
2015031930	\$2,350	\$219	\$2,131	8485	\$9.04
2015032024	\$2,101	\$443	\$1,658	8470	\$7.02
2015071306	\$2,325	\$58	\$2,267	6832	\$7.75
2015071606	\$2,400	\$67	\$2,333	6954	\$8.11
2015071706	\$2,351	\$50	\$2,301	7000	\$8.05
2015071837	\$2,459	\$194	\$2,265	6542	\$7.41
2015072006	\$2,336	\$40	\$2,296	6564	\$7.53
2015072906	\$2,352	\$52	\$2,300	6668	\$7.67
2015080530	\$4,847	\$371	\$4,476	7412	\$16.59
2015082006	\$2,334	\$36	\$2,297	6551	\$7.53
2015111925	\$2,334	\$255	\$2,079	7682	\$7.98
2015112023	\$2,433	\$252	\$2,181	7361	\$8.03
				Total	**\$250**