NEMMCO

National Electricity Market
Management Company Ltd

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Melbourne Office

14 November 2008

Dr John Tamblyn
Chairman
Australian Energy Market Commission
PO Box A2449
SYDNEY SOUTH NSW 1235
By email: submissions@aemc.gov.au

Dear Dr Tamblyn,

SUBMISSION TO AEMC SCOPING PAPER - REVIEW OF ENERGY MARKET FRAMEWORKS IN LIGHT OF CLIMATE CHANGE POLICIES

Please accept this submission on this review by the AEMC into the energy market framework. This submission is based on the AEMC request for feedback on the scope of the review.

NEMMCO assumes that, in conducting this review, the AEMC aims to examine the market framework in light of the dual external policy factors of a Carbon Pollution Reduction Scheme (CPRS) and Renewable Energy Target (RET).

We note that this review is also being undertaken during a period where other external factors, particularly the global financial crisis, are unfolding and the implications for the NEM remain uncertain. It is important that the AEMC either consider this as part of the 'base case' or as part of a scenario which allows the review to consider the extent to which the financial crisis exacerbates the CPRS and MRET impacts.

NEMMCO supports the AEMC approach to undertaking this review, specifically the evidence based assessment of issues and their mitigation options. NEMMCO's approach to responding to the scoping paper has been, in broad terms, to identify where we believe an issue warrants further investigation through the review. Detailed evidence to support NEMMCO's views on respective issues will be provided in response to the subsequent issues paper/interim report.

Please also find attached these historical documents that are referenced in the submission:

1. "Managing Large Changes in Wind Generation Output, Draft Report to Standing Committee of Officials by the Wind Energy Integration Reference Group", Nov 2005.

2. "5 minute Dispatch and 30 minute Settlement Issue, Draft Final Report", June 2002.

For further discussion please call Mark Johnston, Head of NEM Development, 03 9648 8615.

Yours sincerely,

<u>DAVID WATERSON</u>
General Manager
Development and Strategy

1. Convergence of gas and electricity markets

1. How capable are the existing markets of handling the consequences of a large increase in the number of gas-fired power stations and their changing fuel requirements?

As noted in the scoping paper, the NEM is expected to be impacted by a large increase in base-intermediate loading gas-fired combined-cycle technology as a result of CPRS incentives. This technology does not appear to pose any significantly different technical challenges for the NEM design than exists for coal-fired generation.

Gas-fired generation has been shown to be a relatively reliable source of generation and is flexible enough to support dispatch processes. The improved relative cost of gas-fired generation presumably provides an opportunity for retailers to hedge their load exposure for periods of low wind output and high demand with fast-responding plant. A market response of this nature supports NEMMCO's role in ensuring power system security through the dispatch process and ancillary services.

The ancillary services markets continue to be developed by NEMMCO. Growth in gas-fired generation is likely to provide new suppliers of ancillary services available to NEMMCO.

2. What areas of difference between gas and electricity markets might be cause for concern and how material might the impacts of such difference be?

It is acknowledged that Australian gas and electricity markets have developed along different paths for a number of reasons, and in some cases vary between jurisdictions. Despite this, gas fired generation has operated successfully in the NEM and whilst there may be some opportunities for harmonisation, NEMMCO is unaware of any serious operational problems that have arisen to date due to differences in market design.

NEMMCO is unable to comment on the adequacy of the frameworks for the development of increased gas supply and transmission capacity to feed future growth but observes that over 4,000MW of gas-fired generation has been successfully commissioned since NEM start and appears to have procured reliable fuel supplies.

An area of direct impact on the electricity market of the growth in gas-fired generation is emergency management in the event of a major gas supply interruption. Force-majeure events including Longford (1998), Moomba (2004) and Varanus Island (2008) provide examples of events with the potential to severely impact the electricity market and power system. With an increased reliance on gas-fired generation in NEM, it may be worth considering the impact of such large unpredictable events on electricity supply, such as:

- Will the gas markets efficiently ration gas during these extreme events?
- Are the emergency management powers sufficient to address scenarios that may emerge during these events?
- Will gas-fired generators invest in sufficient auxiliary fuel capability to manage such unpredictable events?
- How will competing priorities of supply to direct gas customers and supply to electricity generators in order to maintain supply to electricity customers be managed?

2. Generation capacity in the short term

The statement "by historical standards, existing reserves of generation for electricity are low"[1] may not adequately describe the situation across the NEM. At NEM start, generation reserves in Qld and SA were low and these regions have experienced considerable new investment during the life of the NEM. A comparison of NEMMCO's 1999 list of existing non-intermittent scheduled generation with today's existing and committed projects shows increases of 3635MW in Qld, 1810MW in NSW, 873MW in Vic and 631MW in SA[2]. Greater levels of interconnectivity with QNI, Basslink amongst other transmission investment has also strengthened customer reliability.

NEMMCO produces on its website a regularly updated list of committed and proposed new generation projects. This shows a considerable amount of committed new generation capacity (over 2000MW) in the NSW and Qld regions in the next 3 years. There are also a large number of proposed projects, which, should some of these to progress to committed status, could provide considerable additional capacity.

As noted by the scoping paper, NEMMCO's 2008 Statement of Opportunities (SOO) publication does indicate a projected reserve shortfall during the forecasting period, but this is consistent with previous years' publications and should be interpreted as advice to assist investors in the timing of their investment decisions rather than indicating any particular trend of tightening supply/demand.

3. **What are the practical constraints limiting investment responses by the market?**
4. **How material are these constraints, and are they transitional or enduring?**

Generation investors have always faced a great number of physical and financial challenges in bringing projects to fruition. The level of these challenges has varied in the life of the NEM, for example interest and exchange rate fluctuations have altered project costs. Uncertainty regarding carbon policies has undoubtedly been a factor in recent years and will continue to add risk until these policies are fully clarified.

These costs and risks manifest themselves in minimum projected revenues that investors demand from the wholesale contract and spot markets before they will commit to build. When generator investor costs increase across the board, retailers and ultimately customers, find that they must pay higher prices to contract supply. Where input costs increase, the NEM's spot and contract markets design should in theory result in efficient customer price increases rather than declining levels of investment.

An approach the review may use to consider these issues is to break up the various drivers on generator investor costs and returns for a standard form of generation. In figure 1 we have provided a stylised block diagram of the investor drivers for a gas-fired generator investor.

In relation to physical constraints and delivery timeframes, NEMMCO refers the review to consider the list of proposed generation projects on its website. NEMMCO has been advised of these projects that, should their respective minimum financial returns be considered achievable, are physically capable of delivery in the timeframes listed.

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[1] Scoping paper Pg 2
[2] Increases of summer 2011/12 vs 2002/3 as reported by SOO 2008 and 1999 publications respectively, after adjusting for snowy region elimination.

5. **How material is the likelihood of a need for large scale intervention by system operators? How likely is it that this will be ineffective or inefficient?**

NEMMCO suggests the review should consider the likely extent of powers of intervention in the unfortunate situation where existing generation is required to operate to meet reliability standards but is unwilling or unable to operate due to financial distress. Scenarios that could be tested include insolvent generators, generators under administration and non-scheduled generators.

3. Investing to meet reliability standards with increased use of renewables

6. **How material is the risk of a reduction in reliability if there is a major increase in the level and proportion of intermittent generation?**

Investment in non-intermittent plant

NEMMCO and the Jurisdictional Planning Bodies (JPB's) have focussed efforts in recent years into developing a consistent and robust approach to estimating the contribution of wind farm capacity to overall system reliability. The capacity for which there is 95% confidence of generation at time of regional peak is now used.[3] This results in only a very small wind contribution (8% or less of installed capacity) being used in our reliability forecasting and therefore these outlooks would not be materially over-estimating reliability. Considering this conservative approach and the recent rapid growth in energy-share by wind capacity in South Australia, the short-term reserve outlook nevertheless remains within the Reliability Panel's guidelines[4].

Given the approach of discounting of the capacity of wind for reliability, the key question is whether the market mechanisms provide incentive for the extreme peak of demand to continue to be met from an equivalent level (plus reserve margin) of non-intermittent generation. Critical to the investment question is the role of hedging contracts and/or vertical integration and the need for retailers to find price risk management at times of their customers' peak demands. The investment and reliability forecasting processes could diverge were participants take a more optimistic view of the reliability of wind, with intermittent generation thereby supplying a larger component of price risk mitigation. The review could consider surveying how participants consider the commercial reliability of wind and compare with the approach used by planners.

In 2005 NEMMCO convened the "Wind Energy Integration Reference Group" (WEIRG) from which a number of key improvements have spawned, such as Semi-Dispatch of wind generation. NEMMCO produced the attached document "Managing Large Changes in Wind Generation Output" in November 2005, which discusses these investment processes.[5]

This paper concluded that the market design could acceptably manage the growth in wind farms that was expected at that time, and, to date, that view has been borne out. The expected introduction of the federal government's 20% renewable target will further increase the expected level of intermittent generation. It may be worthwhile for the review to consider

[3] See 2008 SOO Section 3.6.7

[4] Note that the 2008 SOO shows a minor reserve deficit for Vic/SA combined region during 2008/9 summer, however additional studies showed it to remain within the 0.002% unserved energy criterion. (See SOO Executive Briefing Pg 7).

[5] WEIRG 2005 "Managing Large Changes in Wind Generation Output" pg 1

these matters in a similar format as that taken by this 2005 paper, but to subject the analysis to the new target.

An interesting feature that may mitigate this issue is that as an intermittent generation technology becomes significant in a NEM region, prices become inversely correlated to output and therefore earnings for that technology will decline. South Australia is already experiencing low and sometimes negative prices when high wind conditions have combined with low demand. Analysis of NEM data demonstrates that SA wind farms are realising an output-weighted average pool price below the time-weighted average. This should, in turn, discourage investment in that technology in favour of uncorrelated or non-intermittent generation. This mitigating feature should not be overlooked by the review.

Rapid Fluctuations in Supply/Demand Balance

NEMMCO notes that the current 5-minute dispatch design sets prices resulting from effectively a real-time supply/demand balance. Where sudden reductions in generation occur, the next dispatch interval price will take account only of offered generation that can ramp to replace it in the next 5 minutes. This inherently rewards more flexible generation and demand-response (and penalises slower participants) if needed. This should be contrasted with the difficulties faced by hourly-priced markets[6] which must procure more ancillary services.

Note that the sharpness of a 5 minute pricing signal is somewhat affected by the 30 minute time-weighted averaging for settlement used by the NEM. In 2002 NEMMCO consulted upon a possible resolution to this issue using simulated 5 minute settlement[7]. It concluded that the benefits of resolution were outweighed by implementation costs, mainly in retailer systems. However these benefits and costs may have since changed due to growth in intermittent generation and the wider introduction of retail contestability and interval metering. The review may wish to consider whether it is timely for this concept to be re-assessed.

7. What responses are likely to be most efficient in maintaining reliability?

NEMMCO notes that the energy-only market design relies upon individual participants managing their own risks (or taking opportunities) created by price signals, with no central planning role (except as safety-net intervention).

Issues to be considered in that context include:

- The efficiency of financial markets and ease of vertical integration;
- Residual uncertainties in the design of the climate change schemes and the way that markets will price them;
- The recent international financial turmoil; and
- Regulatory risk associated with the consideration of further NEM design change.

4. <u>Operating the system with increased intermittent generation</u>

[6] Harvard Electricity Journal, v21, n7. “An Examination of Capacity and Ramping Impacts of Wind Energy on Power Systems”
[7] See Attached Report: “5 minute pricing and 30 minute settlement issue: Draft Final Report”. June 2002.

8. **How material are the challenges to system operations following a major increase in intermittent generation?**

The NEM is going through a transformative period with an expected growth in wind promoted by renewable energy targets and the emerging CPRS designed to create a change in the generation mix over time. The proportion of intermittent generation that will be installed over time is difficult to predict. It is, however, reasonable to expect that there will be regions what carry a significant share of intermittent generation. Wind is emerging as a dominant intermittent generation source in installed capacity in South Australia and Victoria. South Australia is currently expected to be the region with the highest proportion of intermittent generation.

The anticipated challenges of intermittent generation, even in South Australia, will, in the first instance, be managed by market mechanisms and by tools currently under development by NEMMCO. The market mechanisms are those available to retailers to manage their risk exposure to the intermittent nature of generation and to NEMMCO, as the market operator, to purchase ancillary services that will deliver a secure power system. The tools under developments include the Australian Wind Energy Forecasting System (AWEFS) due for release in November 2008, and mechanisms to support the new market category of semi-scheduled generation (see question 9 for a discussion on these tools).

In relation to the development of market operator tools, the WEIRG paper developed in 2005 to review intermittent generation (see reference to WEIRG in question 6) concluded:

> "…that the main difference between large changes in wind generation and similarly large changes in demand is their relative predictability, and that better forecasting of wind generation would improve the efficiency of the market in managing such changes."[8]

It noted large swings in supply/demand conditions were not new to the NEM, but that wind variation (unlike, say, air-conditioner demand) was something that was not being forecast. Thus the success of the AWEFS in forecasting wind generation is critical to the ability of the NEM to reliably and efficiently accommodate intermittent renewable energy. As the AWEFS is being released only at the time of writing, NEMMCO submits it is too early to conclude whether or not the existing market design and ancillary services, supported by a forecasting system, is able to manage the growth in intermittent generation.

Generation from solar energy is not expected to be material source of generation for some time, particularly in generation capacity large enough to cause material impact to the power system. Distributed or embedded solar generation, for example photovoltaic, will grow over time as various government incentives promote renewable energy. An emerging challenge for market operators will be a level of awareness of the quantity of distributed generation and how much this may impact on demand forecasts. NEMMCO is preparing a rule change submission that will make registration with NEMMCO of small generators more efficient, thereby providing awareness of distributed generation. NEMMCO recommends that the AEMC review into demand side participation seek to identify a framework for the management of the growth in distributed generation.

[8] WEIRG 2005 "Managing Large Changes in Wind Generation Output" pg 1

9. **Are the existing tools available to system operators sufficient, and if not, why?**

As indicated in question 8, NEMMCO is developing tools to manage the power system in light of the growth of intermittent generation. AWEFS is a tool that will provide NEMMCO, wind farm generators and TNSP's with wind energy forecasts in each of the forecast time intervals already forecast by NEMMCO; dispatch, pre-dispatch, ST PASA, MT PASA. AWEFS should provide NEMMCO with the ability to better match supply and demand based on the forecast level of wind available in each dispatch interval. AWEFS is scheduled for release into production in November 2008.

NEMMCO is also developing the capability to manage the new participant registration of semi-scheduled generation. This will provide NEMMCO with the ability to restrict the output of wind farms in the event that their generation would pose a threat to the power system. This capability will be released into production in March 2009.

As neither AWEFS or the semi-dispatch capability has been released it is premature to speculate on whether these will not support the management of the power system as intended.

NEMMCO also has ancillary services available to procure services to ensure the security of the power system. As these are market based mechanisms, NEMMCO will continue to monitor the types and amounts of respective ancillary services required and procure those services as necessary.

Beyond these tools, NEMMCO has established processes to monitor the impacts on the power system as intermittent generation grows. As gaps are identified NEMMCO will take steps to ensure they are addressed promptly. Areas in which ancillary services might be enhanced in the future include the provision of minimum levels of system inertia and localised purchase of regulation services to assist the management of network constraints.

10. **How material is the risk of large scale intervention by system operators and why might such actions be ineffective or inefficient?**

The introduction of wind energy forecasting systems should assist NEMMCO in more accurately assessing system security and short-term reliability. This should assist NEMMCO to use its intervention powers sparingly and efficiently.

The requirement for new wind generators to be subject to the semi-dispatch provisions should also work to mitigate concerns regarding excessive loading of network elements during periods of constraint and thereby limit the situations where intervention is required.

As noted against Question 5, it may be worthwhile for the review to develop scenarios where NEMMCO's powers of intervention in relation to non-scheduled and semi-scheduled generators can be assessed from a legal and practicality perspective.

11. **How material are the risks associated with the behaviour of existing generators, and why?**

In relation to the readiness of other generators to respond to the sharper energy and ancillary services price signals, it is difficult to perform analysis at this time. In particular, the performance of the AWEFS system will be critical to providing adequate warning to other generators of when pricing signals are likely to arrive. Also, previously base-loading generators will need to develop and assess their own capacity to operate more flexibly in response to these new drivers.

5. Connecting new generators to energy networks

13. How large is the coordination problem for new connections? How material are the inefficiencies from continuing with an approach based on bilateral negotiation?

Climate change policies will accelerate the current trend towards the connection of more disaggregated generation sources of smaller unit size promoted by numerous small investors. This has been highlighted by recent experience in California, where there has been a rapid increase of renewable applications such that these now exceed peak system demand[9].

NEMMCO believes the co-ordination issue is also causing administrative inefficiencies in the NEM and this should be a focus for the review. Network Service Providers (NSPs) and NEMMCO face difficulties in providing timely and efficient assessments for the full range of connection applicants.

Confidentiality provisions create further difficulties by limiting the sharing of information between applicants. Sometimes an efficient shared connection solution may not be realised because the parties are not aware of the opportunity nor is NSP at liberty to bring it to their attention.

NEMMCO suggests the review also consider the general question of efficient sequencing of connection applications, considering both the availability of technical resources within NSP's and NEMMCO and situations where one project impacts the technical feasibility of another.

6. Augmenting networks and managing congestion

15. How material are the potential increases in the costs of managing congestion, and why?

In relation to congestion and power system security, NEMMCO believes that the introduction of semi-dispatch and AWEFS addresses immediate concerns that security will be threatened by the growth of intermittent generation. Gas-fired generation is usually fully scheduled and predictable and can similarly be managed. As noted in section 4, NEMMCO will be routinely assessing performance and will move quickly to respond to any deterioration.

18. How material is the risk of inefficient investment in shared network, and why?

NEMMCO suggests that the review could assess the performance of the Regulatory Investment Test (RIT) in relation to the new climate change incentives being Renewable Energy Certificates and CPRS credits. We believe that these instruments, now being explicitly priced, could be encapsulated in the RIT market benefits and therefore not be treated as an externality. It would be useful for if the review were to investigate the issue and provide some guidance to network planners in this regard.

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[9] http://www.nemmco.com.au/about/057-0406.pdf Presentation by CAISO to APEX 2008 conference, pg 11.

7. Retailing

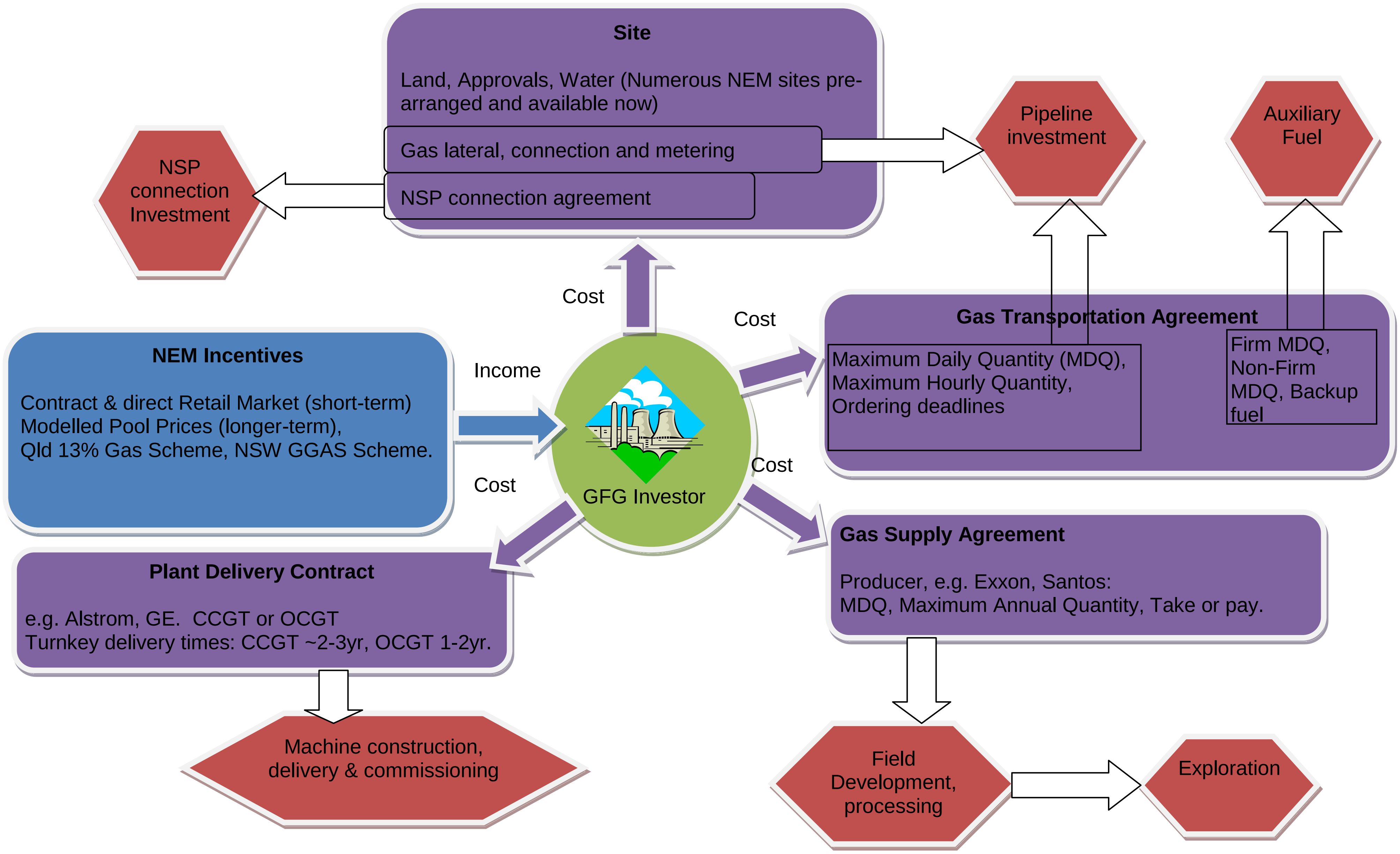
22. How material are the risks of unnecessarily disruptive market exit, and why?

NEMMCO notes that there are a number of related activities underway in this area that are not AEMC led. The Ministerial Council on Energy (MCE) is conducting a review into a national Retailer of Last Resort (RoLR) scheme[10]. NEMMCO is also conducting a consultation on the “Reallocation Procedure for Swap and Option Offset Reallocations”. NEMMCO continues to work with industry on enhancing the re-allocation process as a mitigation to help avoid unintended market exits.

The review should also consider whether a review of NEM prudential arrangements is necessary noting, for example, a retailer provides guarantees of one form or another to NEMMCO, DNSP’s, Australian Stock Exchange (ASX) for futures trading and counterparties through Over the Counter (OTC) trading. Mitigation actions though further efficiencies in the settlement and prudential processes should be considered to minimise the potential for involuntary market exit(s).

[10] MCE review of a National Policy Framework for Retailer of Last Resort: http://www.mce.gov.au/assets/documents/mceinternet/Release%20of%20the%20Retailer%20of%20Last%20Resort%20combined%20file20081003154023.pdf

Figure 1: Stylised Representation of Drivers of investment for a Gas-Fired Generator (GFG)



NEMMCO

National Electricity Market
Management Company Limited
ABN 94 072 010 327

Managing Large Changes in Wind Generation Output

Wholesale Market Development

Version No: 5.0

November 2005

DRAFT

1. Introduction

The Standing Committee of Officials (SCO) of the Ministerial Council on Energy (MCE) has asked NEMMCO to evaluate "the ability of the current market mechanisms to provide adequate generating plant response to compensate for large changes in wind generation output as have been forecast in modelling undertaken by the Electricity Supply Industry Planning Council (ESIPC) in its Wind Report to the Essential Services Commission of South Australia (ESCOSA)". In other words, the SCO has asked NEMMCO to investigate whether the current market design can successfully manage large changes in wind generation. The sorts of large changes considered in this paper are of the order of hundreds of MWs over one or more trading intervals.

Because wind generation is a topical issue in the National Electricity Market (NEM) at present, there are also a significant number of parallel work streams being progressed to integrate wind generation into the NEM. While the results of those work streams may have a peripheral effect on this paper's conclusions, particularly the investigations into improving forecasts of wind generation, this paper is intended to be read as a stand-alone document.

This paper starts by discussing the large changes in wind generation that were foreshadowed in the ESIPC report. The paper goes on to look at actual observations of wind generation in South Australia, and some of the potential effects that large changes in wind generation might have on the power system.

The paper then discusses the existing market mechanisms that are designed to deal with inherent uncertainties in the physical system, and gauges whether those mechanisms might also address large changes in wind generation. Particular emphasis is placed on the contracting arrangements that are used to manage spot price risk in the NEM, and the physical capacity that is used to back those contracting arrangements.

The paper concludes that the existing market design should be sufficient to cope with large changes in wind generation, under the current policy framework, over at least the next several years. The paper also suggests that the main difference between large changes in wind generation and similarly large changes in demand is their relative predictability, and that better forecasting of wind generation would improve the efficiency of the market in managing such changes.

2. Forecast Large Changes in Wind Generation Output

The output from wind generation fluctuates. Small variations in the output from wind generation are expected to be managed by the regulation frequency control ancillary services (FCAS). However, the output from wind generation can also display larger variations. In particular, the generation from a wind farm can fall from full capacity to near zero relatively quickly and relatively unpredictably. This is likely to place additional stresses on the job of continuously balancing supply and demand as the amount of wind generation in the NEM increases.

Rising output from wind generation might increase regional exports, displace local synchronous generation, or collapse local spot prices, in which case there may be an incentive for wind generators to moderate the rate at which their output increases, depending on the extent to which their output is sold at the local spot price. On the other hand, falling output from wind generation could lead to an increase in regional imports or the output from local synchronous generation – with an associated increase in local spot prices – but there might also be insufficient import capacity or synchronous ramp rate available to meet local demand regardless of the local spot price if there is a large fall in wind generation.

South Australia is the region where these sorts of issues seem most likely to be encountered in the NEM. This is because the amount of wind generation capacity in South Australia is already relatively high as a proportion of regional demand, and because South Australia is relatively weakly interconnected with the rest of the market. Furthermore, the amount of wind generation capacity in South Australia is expected to increase significantly over the next few years. Consequently, this paper often focuses on the South Australian situation when discussing large changes in wind generation output. However, any potential solution for the challenges facing South Australia should, ideally, be generally applicable to the NEM.

The following sections discuss:

- the nature of the large changes in wind generation that were forecast in the ESIPC report;
- the observed output from wind generation in South Australia; and
- some of the potential effects that large changes in wind generation output might have on the operation of the power system.

2.1 ESIPC Report

The scope for large changes in the output from wind generation in South Australia was highlighted in the ESIPC report to ESCOSA in April 2005. An essential feature of the ESIPC report was that it attempted to quantify the size and frequency of the large changes in wind generation that might be expected for different amounts of wind generation capacity installed in South Australia.

The ESIPC report forecast that with 400 MW of wind generation installed in South Australia, then once a year the output from wind generation might vary by around 360 MW over six hours. South Australia is expected to have around 400 MW of wind generation installed by the end of 2005. The ESIPC report also forecast that with 1,000 MW of wind generation installed in South Australia, then once a year the output from that wind generation might vary by 950 MW over six hours, or by 500 MW over just half an hour. Further details from the ESIPC report are discussed in Appendix 1 of this paper.

2.2 South Australian Data

By mid-2005 South Australia had around 320 MW of wind generation installed, up from around 160 MW at the start of the year. The minimum amount of wind generation capacity for which forecasts were developed in the ESIPC report was 400 MW. Consequently, the ESIPC forecasts are not directly comparable to the data on actual wind generation in South Australia. However, actual wind generation shows the sorts of characteristics highlighted in the ESIPC report, and provides no reason to question the accuracy of the ESIPC forecasts at this stage.

Chart 1 shows the total output from South Australian wind generation on 11 August 2005. This is the aggregate output from the Canunda, Cathedral Rocks, Lake Bonney, Starfish Hill and Wattle Point wind farms for that day.[1] The output was measured using 4-second SCADA data sampled at 1-minute intervals. As well as displaying general volatility, Chart 1 shows frequent fast large falls in wind generation output as a proportion of installed capacity.

[1] 11 August 2005 was chosen because it was close to the first of the Wind Energy Industry Reference Group (WEIRG) meetings convened to address large changes in wind generation, and because it showed clearly the potential variability of wind generation.

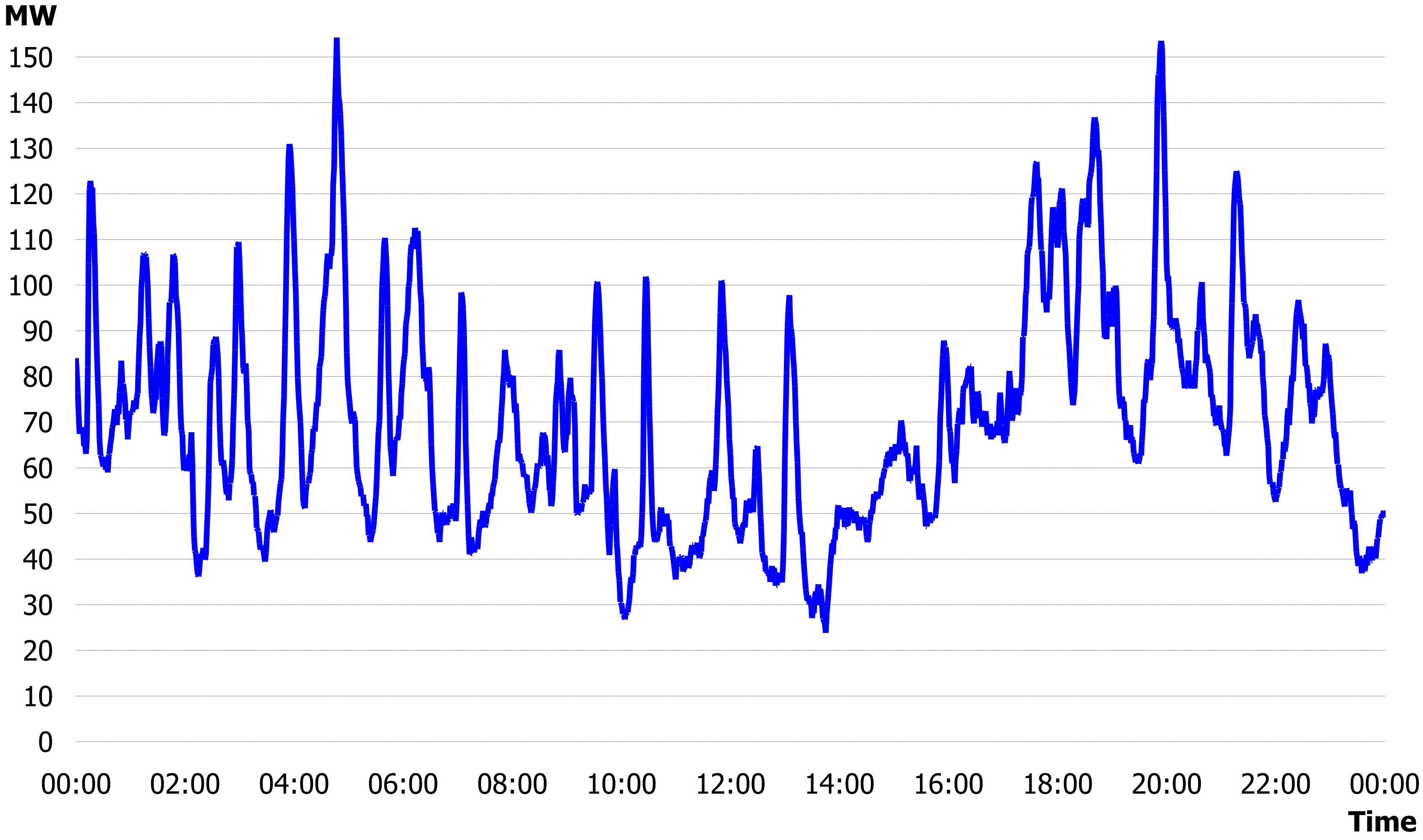


Chart 1: South Australian Wind Generation Output 11 August 2005

2.3 Potential Effects on the Power System

As mentioned earlier, falling output from wind generation could lead to an increase in regional imports, an increase in local synchronous generation, or both. However, if there is a large fall in wind generation there might also be insufficient import capacity or synchronous ramp rate to meet local demand.

Much will depend on the available ramp rate of the local synchronous generation during any large changes in wind generation. In the case of South Australia, if there is insufficient local ramp rate then the Vic-SA interconnector will attempt to meet any difference between local demand and local supply. However, depending on the extent of the imbalance between local demand and local supply, the interconnector may become overloaded, placing the power system in an insecure state. Furthermore, if a generator contingency occurred in South Australia while the power system was in an insecure state, this could lead to load shedding in South Australia.

In order to provide adequate ramp rate in the event of a large fall in wind generation, local generation would need to be synchronised and have spare capacity at times when it might be called on. The purpose of this paper is to investigate whether the current market mechanisms will provide an incentive for this to happen in the NEM. The relevant market mechanisms, and the attendant financial incentives, are discussed in more detail in the following sections.

3. Existing Market Mechanisms

The financial market is designed to manage the spot price uncertainty inherent in the physical market. Spot prices in the NEM are set by a complicated interplay of participant behaviour and physical limitations. Because the spot price can be volatile, and can vary anywhere between a floor of -$1,000/MWh and a ceiling of $10,000/MWh, most electricity traded in the physical market is also hedged in the financial market.

Since the output from wind generation is generally less controllable than the output from synchronous generation, greater amounts of wind generation will tend to increase uncertainty in the physical market. However, there are many sources of uncertainty in the physical market. Increasing wind generation will tend to add to existing uncertainty, rather than introduce uncertainty where there was none before. Consequently, there appears to be no immediate reason why the existing financial market mechanisms for coping with uncertainty in the physical market will not be equally applicable to, and able to cope with, the additional uncertainty arising from wind generation.

Relying on the financial market to manage price and supply uncertainty in the physical market requires three principal assumptions:

1. that retailers will appropriately manage their risk;
2. that sufficient hedges will be available; and
3. that any hedges will be backed by physical capacity.

If these assumptions hold true, then physical demand should always be met by physical supply, apart from in exceptional circumstances such as network contingencies. The following sections address each of the three assumptions in turn, with particular reference to the increasing levels of wind generation in the NEM, and whether the current market design will ensure that sufficient synchronous capacity is available to cover any significant shortfall in wind generation.

3.1 Assumption 1: Retailers Will Appropriately Manage Their Risk

Retailers tend to sell electricity at fixed prices. In order to offer fixed prices, retailers need to be confident about their costs. Because spot prices can vary so much and so rapidly, retailers usually try to cover most of their physical demand with financial contracts in order to gain the necessary confidence over their prospective costs. However, the actual positions taken by retailers to most appropriately manage their risk will depend on their expectations of market outcomes, and on their willingness to expose themselves to risk.

In practice, retailers cannot generally afford not to cover their physical demand, except at the margins. With a price cap of $10,000 / MWh, 100 MW of unhedged demand could cost a retailer $1 million / hour. 100 MW is not a large amount in a market with a peak demand of around 30,000 MW, and retailers generally have more to lose than they stand to gain through being unhedged.

Retailers have traditionally attempted to hedge their physical demand with financial contracts supplied by generators, and typically hold a broad suite of financial contracts in order to cover their load. These financial contracts may take the form of swaps – which provide relative certainty over costs – or caps – which provide an upper limit to costs – or other, more exotic products. However, the key point is that retailers generally try to manage their risks in the physical market using contracts in the financial market.

The incentive for retailers to hedge their load is likely to become even stronger with increasing levels of wind generation in the NEM. Retailers hedge their load in order to manage the spot price uncertainty inherent in the physical market, and greater levels of wind generation will tend to add to that uncertainty. As the level of spot price uncertainty increases, the incentive for retailers to hedge their physical demand will also increase. The possibility that retailers might not be able to hedge their physical demand using financial contracts is discussed further in the following section.

3.2 Assumption 2: Sufficient Hedges Will Be Available

Just as retailers need to be confident about their costs, generators like to be confident about their revenue. Generators need to cover not only the variable costs of running their plant, but also the fixed costs of owning it. Consequently, generators typically have an incentive to offer financial contracts to retailers, subject to the physical availability of their plant. Plant availability might be influenced by plant capacity, fuel supply, planned maintenance, unscheduled outages, or network constraints.

If the aggregate quantity and variety of financial contracts that retailers require is greater than the physical availability of plant, then the price of financial contracts will tend to rise until the supply-demand balance is restored. This might happen through reduced demand, but is more likely to happen through increased supply as more physical capacity becomes available in response to increased prices. This is the mechanism that the NEM relies on to ensure that there is sufficient installed generation to meet overall demand, and this is why there is no capacity market in the NEM.

Ultimately, however, the prices at which generators choose to offer financial contracts may be unacceptably high to retailers. In this case, since retailers need to hedge their load, they may decide to buy or build their own generation to provide a physical hedge. In other words, if retailers cannot hedge their physical demand in the financial market at a satisfactory price, then they may enter the physical market themselves, becoming vertically integrated entities in the process. This behaviour has already been observed in the NEM.

3.3 Assumption 3: Hedges Will Be Backed By Physical Capacity

Generators who sell financial contracts must back them with appropriate physical capacity in order to manage their financial risks. The appropriate level of physical capacity will depend on the judgements of individual generators regarding the aggregate supply curve in the market at any time and their consequent expectations of market outcomes. If individual generators believe that the spot price will stay below the strike price of their contracts, then they may prefer to let demand be supplied by other generators. However, if individual generators believe that the spot price may rise above the strike price of their contracts, they will have a financial incentive to ensure that their own physical capacity is available to generate should that happen. With a price cap of $10,000 / MWh, 100 MW of financial contracts could cost a generator $1 million / hour if they cannot generate at the appropriate time.

Similarly, any generating plant built or bought by a retailer because the price of financial hedges was unacceptable to them must be synchronised and ready to generate at the appropriate time in order to provide a reliable physical hedge for the retailer’s demand.

In the South Australian situation, if a large fall in wind generation led to overloading of the Vic-SA interconnector, then the spot price in South Australia could be expected to rise as the interconnector flow approached its secure limit. Any generators that had sold financial contracts in South Australia would then have a strong incentive to be synchronised and ready to generate before the spot price increased above the strike price of their contracts. Similarly, any retailers who controlled generating plant as a physical hedge would have an incentive to ensure that the plant was synchronised and ready to generate at the appropriate time in order to manage their spot price exposure and, when necessary, meet their physical demand.

The incentive for generators to back their financial contracts with physical capacity is likely to become even stronger with increasing levels of wind generation in the NEM. Generators back their financial contracts with physical capacity in order to manage the spot price uncertainty inherent in the physical market, and greater levels of wind generation will tend to add to that uncertainty. As the level of spot price uncertainty increases, the incentive for generators to back their financial contracts with physical capacity will also increase.

4. Managing Large Changes in Wind Generation in the NEM

Section 2 of this paper discussed the large changes in wind generation that were forecast in the ESIPC report, and their potential to reduce security and disrupt supply in the NEM without a suitable market response. Section 3 discussed the market mechanisms that are designed to deal with the inherent uncertainty in the physical system, and proposed that physical demand will be matched by physical supply provided:

- retailers appropriately manage their risk;
- there are sufficient hedges available; and
- any hedges are backed by physical capacity.

This section considers whether the NEM, which is already designed to cope with a considerable amount of uncertainty, can cope with the size and nature of the uncertainty that will be introduced by increasing amounts of wind generation. The section concludes that the existing market design should be sufficient to cope with large changes in the output from wind generation, under the current policy framework, over at least the next several years, and draws comparisons between large changes in wind generation and similarly large changes in demand. This section goes on to suggest that the main difference between large changes in wind generation and large changes in demand is their relative predictability, and that better forecasting of large changes in wind generation would improve the efficiency of the market as the amount of wind generation in the NEM increases.

4.1 Comparison With Large Changes in Demand

Chart 2 shows South Australian price and demand on 11 August 2005. This is the same day for which total output from South Australian wind generation was shown in Chart 1. The demand curve for that day shows a fairly typical winter profile, with a slightly higher overall peak demand than usual. Of particular interest for this discussion is the morning ramp period from around 5:30 a.m. to 9:30 a.m.

The ESIPC report forecast that with 400 MW of wind generation installed in South Australia, then once a year the output from wind generation could fall by around 360 MW over six hours. Wind generation in the NEM is treated as negative demand, since every MW of wind generation is equivalent to one less MW of demand that needs to be met by scheduled generation. Conversely, every MW decrease in wind generation is an extra MW that needs to be supplied by scheduled generation. Therefore a 360 MW decrease in wind generation over six hours is equivalent to a 360 MW increase in demand over the same period.

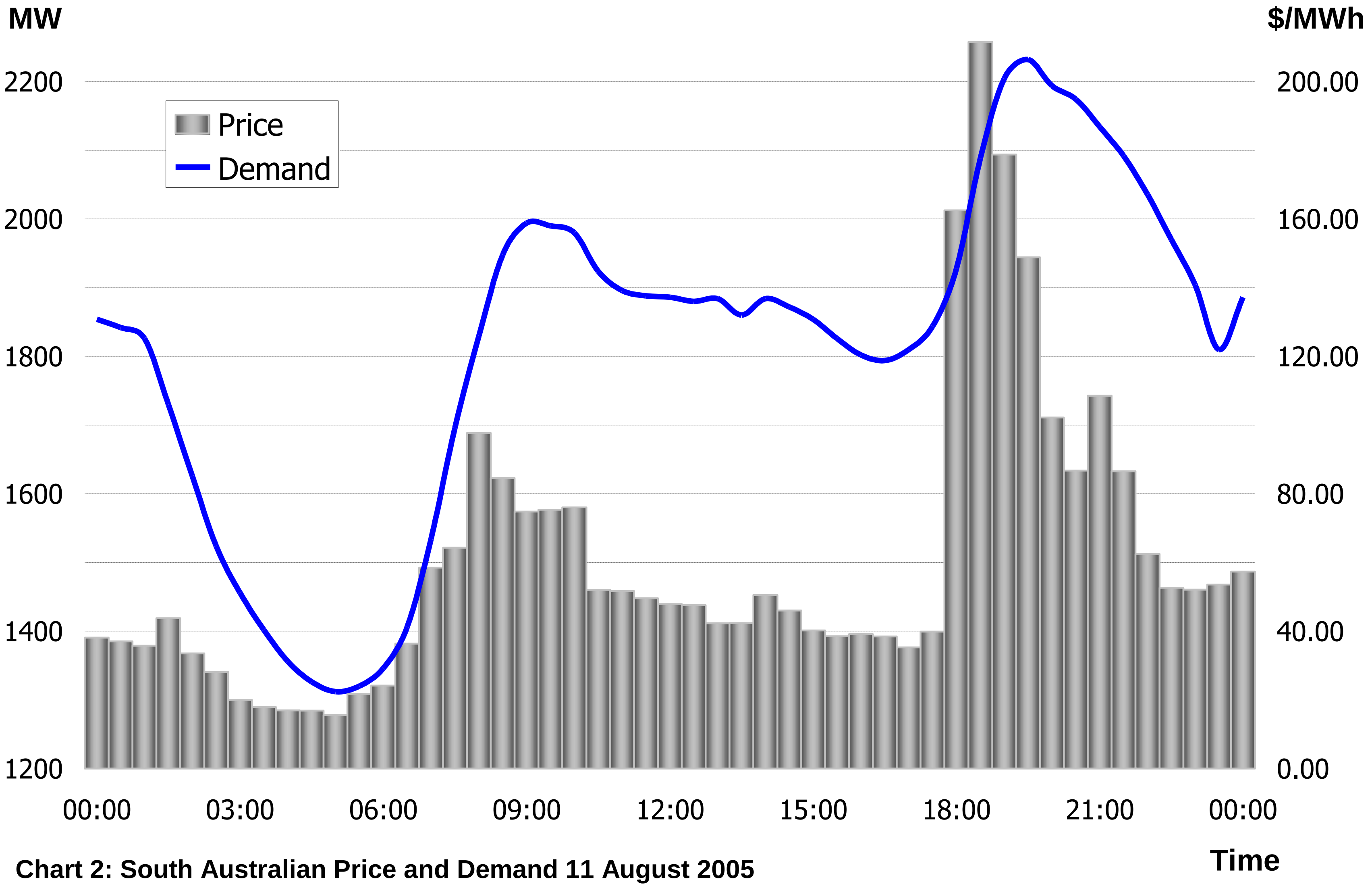


Chart 2: South Australian Price and Demand 11 August 2005

However, during the morning ramp in South Australia on 11 August 2005, demand increased by around 700 MW over only four hours. Prices during this period were relatively high, which is unsurprising since it was a day of relatively high demand. Most importantly though, prices did not reach VoLL, indicating that although demand rose by 700 MW over four hours, there was sufficient generation available to meet that increase in demand.

It seems apparent then that the power system can cope with wind generation changes of the size forecast in the ESIPC report. What still needs to be investigated is whether the power system can cope with the uncertainty and limited forewarning of the timing of any large changes in wind generation, and with any increased demand for ramp rate response from synchronous generators. These issues are discussed in the next section.

4.2 Effect of Uncertainty in the NEM

Changes in demand are generally more predictable than changes in wind generation. Demand is largely a function of the time of day and day of the week, with some adjustment for season and temperature. Wind generation is largely a function of the weather – most notably wind speed – and is generally more volatile.

Because wind generation fluctuates, it will tend to introduce more uncertainty to the supply-demand balance in the physical market, and therefore to spot prices, as discussed in earlier sections of this paper. Greater uncertainty in markets usually leads to higher prices and less efficiency. While this normally adds to the costs of doing business, it does not generally stop business being done.

Furthermore, although demand forecasts currently seem more reliable than wind generation forecasts, demand forecasts still contain uncertainties, both in terms of the overall volume of demand, and occasionally in terms of the timing of any significant changes as well. Thus increasing amounts of wind generation will tend to add to existing uncertainty in the supply-demand balance in the NEM, rather than introduce uncertainty where previously there was none.

If wind generation forecasts were more accurate, this would tend to reduce the cost of ensuring that hedges are backed by appropriate physical capacity, which would in turn tend to reduce the price of hedges, and thus increase the efficiency of the market. In the case of peaking plant, which is normally off, the costs of ensuring that hedges are backed by appropriate physical capacity would include start up costs at times when there was a chance that the plant might be called on, whether it was actually called on or not. In the case of intermediate plant, which is frequently on, the costs of ensuring that hedges are backed by appropriate physical capacity would include the opportunity costs of maintaining spare capacity – that could otherwise be generating – at times when there might be a large fall in wind generation, whether there was a large fall in wind generation or not.

The aggregate amount of generating plant that needs to be available to cover any large falls in wind generation is dependent on the amount of wind power being generated at the time. For example, if there was 1,000 MW of wind generation installed in South Australia but it was generating only 500 MW, then there would be no need to have more than 500 MW of local spare, synchronised capacity available to replace the wind generation, even if that wind generation died away completely and instantly. In practice, any large falls in wind generation due to changing weather conditions would be gradual, and probably take place over a greater interval than the time required for a fast start generator to synchronise. The amount of spare, synchronised capacity needed to offset any potential large shortfall in wind generation could be reduced further depending on the amount of headroom on the Vic-SA interconnector at the time, and might be reduced still further if there were reliable forecasts of the weather patterns that would lead to a large fall in wind generation. Work is currently underway to improve forecasts of wind generation in the NEM.

However, even in the absence of improved wind generation forecasts, the assumptions discussed in Section 3 – that retailers will appropriately manage their risk, that there will be sufficient hedges available, and that any hedges will be backed by physical capacity – should be sufficient to ensure that physical demand is matched by physical supply, apart from in exceptional circumstances such as network contingencies. These are the mechanisms that the market relies on at the moment to ensure that demand is met by supply.

At this stage there is no evidence that any of these assumptions will break down with greater amounts of wind generation in the NEM. If anything, the assumptions will hold truer as the financial drivers to manage risk become stronger due to the greater market uncertainty arising from increased amounts of wind generation. Nevertheless, NEMMCO would continue to monitor developments as the amount of wind generation capacity installed in the NEM increases, to guard against any unforeseen consequences from relying on the existing market mechanisms.

4.3 Potential Future Options

The NEM is already designed to accommodate a considerable amount of uncertainty. It is the WEIRG's view that the existing market mechanisms should be sufficient to cope with any additional uncertainty introduced by large changes in the output from increasing amounts of wind generation, under the current policy framework, over at least the next several years. However, in case there are unforeseen consequences from relying on the existing market mechanisms, the WEIRG also identified a range of options that might be used to manage large changes in wind generation should the need arise in the future.

4.3.1 Existing FCAS

There are currently two main types of FCAS. Regulation FCAS is designed to manage small frequency deviations within a dispatch interval, while contingency FCAS is designed to restore system frequency following a contingency, such as a generating unit trip. To the extent that wind farms might credibly trip, they will be included in the contingency FCAS requirements. However, generator trips are instantaneous, whereas the large changes in wind generation being considered in this paper are more gradual. Consequently, contingency FCAS is not an appropriate mechanism for managing large changes in wind generation. However, to the extent that wind farm variability represents an uncontrollable change in the supply-demand balance within a dispatch interval, then regulation FCAS could be an appropriate mechanism for managing large changes in wind generation.

NEMMCO continually reviews the quantity of regulation FCAS required to meet the frequency standards set by the Reliability Panel for the NEM. There is an expectation that greater amounts of wind generation will eventually lead to a greater requirement for regulation FCAS. That need has yet to emerge. If and when the need does emerge, NEMMCO will revise the regulation FCAS requirement accordingly, and may consider time-profiled or dynamic FCAS requirements as well.

The WEIRG noted that if there is a need to introduce dynamic FCAS requirements in response to increasing amounts of wind generation in the NEM, then it may also be appropriate to review the timeframe of the causer pays arrangements. Causer pays arrangements for regulation FCAS are currently calculated on a 28-day cycle. A shorter cycle, or even real-time calculations, would sharpen the price signals arising from more dynamic FCAS requirements. The WEIRG considers that these issues should be addressed when NEMMCO fulfils its National Electricity Rules obligations to review the operation of the FCAS markets.

4.3.2 New Ancillary Service

It is worth noting though, that regulation FCAS was designed to address small frequency deviations within a dispatch interval. Depending on the amount of wind generation capacity installed in the NEM, regulation FCAS may not be appropriate for addressing changes in wind generation output of the scale and duration being considered in this paper. An alternative approach may be to introduce a new ancillary service to cope with large changes in wind generation output, should indications of a need for such a service start to emerge.

A new ancillary service to cope with large changes in wind generation would probably be required to operate over a number of trading intervals, rather than the shorter timeframes over which existing FCAS operates. If a potential need for such a service was identified, then as a minimum, the interactions of such a service with the existing energy and FCAS markets, along with Network Control Ancillary Services (NCAS), would need to be explored. The issue of who should pay for the service would also need to be addressed. Under the causer pays principle that underpins other FCAS payments, it appears likely that wind farms would be required to pay for the service.

4.3.3 Trading Interval Length

The WEIRG also considered that should the need arise, it might be appropriate to consider reducing the length of the NEM trading interval from 30 minutes to 15 minutes. This was suggested as a means of sharpening the price signals faced by market participants in response to any large changes in wind generation.

5. Conclusions

The types of large changes in wind generation foreshadowed in the ESIPC report appear credible. There is the potential for wind generation to fall relatively quickly and relatively unpredictably from near capacity to near zero. Even though such events might be rare, the power system should be designed to cope with rare events.

In the absence of a suitable market response, there is a risk that a large fall in wind generation might lead to an inability to meet demand through alternative sources of generation. However, so long as retailers appropriately manage their risk, there are sufficient hedges available, and hedges are backed by physical capacity, then physical demand should always be matched by physical supply, apart from in exceptional circumstances such as network and non-credible contingencies, which is also the case at the moment.

At this stage there is no evidence that the financial market linkages between physical supply and physical demand will break down in presence of increasing levels of wind generation. If anything, the linkages will grow stronger because of the greater need to manage the rising uncertainty introduced by increasing amounts of wind generation. However, improved forecasting of wind generation should improve the efficiency of the market by reducing that uncertainty, and consequently the cost of hedging.

In conclusion, the WEIRG and NEMMCO consider that the existing market mechanisms should be sufficient to cope with large changes in output arising from increasing volumes of wind generation in the NEM, under the current policy framework, over at least the next several years. Nevertheless, NEMMCO would continue to monitor developments as the amount of wind generation capacity installed in the NEM increases, to guard against any unforeseen consequences from relying on the existing market mechanisms.

Furthermore, in case there are any unforeseen consequences from relying on the existing market mechanisms to manage large changes in wind generation output, the WEIRG identified a range of options that might be used should the need arise.

Appendix 1

> The ESIPC report forecast that with 1,000 MW of wind generation installed in South Australia, then once a year the output from that wind generation might vary by 950 MW over six hours, or by 500 MW over half an hour. In comparison, the average demand in South Australia is around 1,500 MW.

The scope for large changes in the output from wind generation in South Australia was highlighted in the ESIPC report to ESCOSA in April 2005. ESIPC studied half-hourly average wind generation output, and modelled the distribution of MW changes in that output over different periods for different amounts of wind generation capacity installed in South Australia. Information on the methodology used by ESIPC is available in their report.[2] Some of the results of ESIPC's modelling are shown in the following tables. These tables show the MW variation that is expected to be met or exceeded over a defined period on a given percentage of occasions.

Occurrence	Half-Hourly	Hourly	2 Hours	3 Hours	4 Hours	6 Hours
10%	38.6	59.6	90.6	116.6	138.3	172.4
5%	50.2	77.1	116.7	147.4	172.5	208.3
2%	65.5	100.1	148.5	184.3	210.9	246.8
1%	77.1	116.8	170.3	207.9	235.8	272.4
Once a Year	153.2	214.8	284.8	322.3	342.1	359.8

Table 1: MW Variation with 400 MW of Wind Generation in South Australia

Table 1 shows that with 400 MW of wind generation capacity in South Australia – the amount expected to be installed there by the end of 2005 – the output from that generation is forecast to change by 100 MW over an hour on 2% of occasions. Since this modelling has a half-hourly resolution, and there are 48 half-hours in a day, this means that the output from 400 MW of wind generation in South Australia is forecast to change by 100 MW over an hour roughly once a day. Similarly, Table 1 shows that the output from 400 MW of wind generation in South Australia is forecast to change by nearly 250 MW (246.8 MW in the table) over six hours roughly once a day. Since the largest contingency that the NEM typically caters for in South Australia is the instantaneous loss of a 260 MW unit at Northern power station, the loss of 250 MW of wind generation over six hours may not seem like a material issue. However, Table 1 also shows that the output from 400 MW of wind generation in South Australia could change by 360 MW over six hours once a year.

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2 http://www.esipc.sa.gov.au/webdata/resources/files/Planning_Council_Wind_Report_to_ESCOSA.pdf

Occurrence	Half-Hourly	Hourly	2 Hours	3 Hours	4 Hours	6 Hours
10%	113.6	192.1	300.3	383.2	449.7	546.3
5%	156.7	261.3	389.4	481.1	552.9	648.4
2%	210.8	339.5	483.9	587.9	656.2	741.9
1%	252.0	389.5	544.8	647.3	715.9	789.5
Once a Year	495.9	653.9	804.5	873.7	902.0	954.1

Table 2: MW Variation with 1,000 MW of Wind Generation in South Australia

Table 2 shows that with 1,000 MW of wind generation capacity installed in South Australia, the output from that generation is forecast to change by around 340 MW over an hour on a daily basis. Table 2 also shows that once a year the output from 1,000 MW of wind generation is forecast to change by around 950 MW over six hours, or nearly 500 MW in just half an hour. By way of comparison, the average demand in South Australian is around 1,500 MW.

1,000 MW of wind generation capacity is 600 MW more than the amount likely to be installed in South Australia by the end of 2005. However, NEMMCO understands that ESCOSA, which is the organisation responsible for licensing wind farms in South Australia, currently has more than 1,500 MW of applications for further wind generation licences.[3] In other words, it seems reasonable to consider whether the NEM can manage the changes in wind generation that might occur with this level of capacity installed in South Australia.

3 ESCOSA spokesperson, NEM Forum, 6 July 2005

National Electricity Market
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5 Minute Dispatch and 30 Minute Settlement Issue:

Draft Final Report

Prepared by: Market Development
Version: 1.0

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Executive summary

This paper presents the findings from NEMMCO's investigation into the five minute dispatch and 30 minute settlement anomaly in the NEM. This aspect of the NEM has been referred to as the "5/30 Issue".

The NEM uses a 5 minute dispatch interval which produces dispatch targets for generators and scheduled loads, and a cleared marginal spot price for each 5 minute dispatch interval. Settlement, however, takes place using a 30 minute pricing interval which is calculated as the average of the 5 minute dispatch prices to settle the energy market for the 30 minute trading interval.

NEM participants who can effectively respond to five minute price signals face limited market opportunities under the current market arrangements in regard to the physical capability of their assets. Examples of these participants include hydro generators, fast start generators and market network service providers (MNSPs).

NEMMCO has a Code objective[1] to promote changes that improve market efficiency and therefore conducts investigations on NEM issues such as the 5/30 Issue with this clear aim in mind.

NEMMCO established a working group in April 2001 comprising representatives of all sectors of the NEM. Representatives were sourced where possible from industry groups such as the NGF, NRF, and EUAA to ensure the widest level of industry views were presented to the working group at all stages of the investigation.

The working group studied the impact of the 5/30 issue on all sectors of the NEM and developed eight potential options to address the issue in addition to the default "no change" option. An evaluation criteria was developed to reduce the options to the best one or two options for detailed evaluation. The working group identified one preferred option for detailed cost / benefit evaluation [Option 1.1(b) – 5 minute dispatch and Simulated 5 minute settlement] with the NRF representatives insisting that a second option be evaluated due to perceived low costs for retailers [Option 2.2 Hybrid demand weighted option]. The evaluation compared each option relative to the "no change" scenario.

It should be noted that **Option 2.2 is now not considered to be acceptable**. Further detailed analysis during the evaluation stage on settlement implications has led both NEMMCO and the working group (including the retailer representatives who originally supported Option 2.2) to believe that option 2.2 was not desirable and would in fact create serious issues in the NEM. This was due to complications in the following areas:

- financial markets trading difficulties due to effectively different prices being seen for the supply and demand sides of the NEM due to the volume weighting methodology being different for generators and market customers. Divergent views would then arise as to the structure of appropriate hedge contracts;

- the need for mandatory 5 minute interval metering for generators, interconnectors and MNSPs in order to achieve balanced settlements; and in particular,

[1] NEMMCO objectives: NEM Code clause 1.6.2(b)

- the necessity to produce trading interval price estimates in real time with all trading interval prices requiring revision at the end of each week to balance settlements when 5 minute interval meter data becomes available. SCADA data would be required to produce the interim trading interval prices.

The last issue represents a real threat to the reliability of published pool prices due to the reliability of SCADA data would therefore undermine confidence in the NEM. For this reason, NEMMCO would not support any promotion of Option 2.2. Option 1.1(b) therefore became the only credible option for consideration to address the 5/30 Issue during the analysis phase of the project.

Working group members identified the net increase in costs associated with each option for their respective industry sectors with NEMMCO aggregating these net costs for each option. The majority of costs for both options reside with retailers who employed an additional cost analysis step of distributing a cost survey to all retailers via the NRF to produce cost estimates.

NEMMCO engaged McLennan Magasanik Associates (MMA) as independent consultants to identify and quantify benefits to the market in terms of efficiency for both options. The working group worked closely with MMA during the formulation of their analysis methodology and provided an understanding of behavioural changes that would result from the dispatch and settlement arrangements for each option.

A monte carlo simulation approach was used by MMA to quantify the benefits for each option over four differing scenarios including sensitivity analysis to both the period of the study (nominally ten years) and discount rate. The scenarios addressed the most probable (medium) and high demand growths, a cycling scenario where demand and supply oscillate over the study period and a “No Basslink” scenario.

MMA then added the total quantified benefits to the working group’s total cost estimates to produce a Net benefit for each option. A positive Net Benefit would indicate that the option provides a net improvement to market efficiency. The total costs, total benefits and the Net Benefit for each option are shown in the table below in mid 2002 dollars for a study period of ten years and 7% discount rate.

Quantitative Results

	Option 1.1(b) ($M)	**Option 2.2 ($M)**
Quantified Costs (Working Group members)	**160.2**	**54.4**
Quantified Benefits (MMA)		
Medium Growth	**28.8**	**27.4**
No Basslink	**36.2**	**32.8**
Cycling	**39.5**	**36.9**
High Growth	**48.9**	**45.0**

NET BENEFITS	Option 1.1(b) ($M)	Option 2.2 ($M)
Medium Growth	**-131.3**	**-27.0**
No Basslink	**-124.0**	**-21.6**
Cycling	**-120.6**	**-17.5**
High Growth	**-111.3**	**-9.4**

Clearly, these quantified Net Benefit results indicate that neither option provides a net quantifiable improvement to the market in terms of market efficiency – a result that is robust to both discount rate and study period.

Non-quantified Costs and Benefits

Non-quantified and non-quantifiable (qualitative) costs and benefits have been considered by the consultant in the analysis. Non-quantified and qualitatively assessed costs are identified in Appendix 4 of this document and consist of a number of elements considered to be immaterial to the outcome of the study. The non-quantified (but potentially quantifiable) costs were an order of magnitude less than more prominent quantified cost areas.

The magnitude of benefits to be yielded from non-quantified and qualitative factors are more difficult to establish. However, the consultant has identified and qualitatively assessed a number of items in the financial markets area that may deliver some benefits. In the opinion of the consultant, these speculative or potential benefits were not capable of being quantified with any level of accuracy.

Financial Transfer Payments

NEMMCO acknowledges the views expressed to date by parties promoting changes aimed at solving the 5/30 issue and has to this point allocated significant resources to investigate the issue. Industry representatives have also dedicated significant resources in supporting NEMMCO's 5/30 issue investigation. On the basis of the analysis performed in this project, a proportion of the impact arising from the 5/30 issue and its resolution lie in the allocation of financial transfer payments2 rather than in efficiency impacts. NEMMCO does not consider it is in a position to promote change on those grounds alone, particularly in view of the finding that a net industry cost is likely to be incurred in proceeding with any such change. Nevertheless, NEMMCO acknowledges that these transfers may be significant to the stakeholders concerned, and that they may wish to pursue this with parties that are in a position to apply broader criteria to the assessment of change than NEMMCO.

[2] Distribution payments (or transfer payments) as described by MMA in their final report.

Findings

Following two significant investigations into the 5 minute dispatch and 30 minute settlement issue, NEMMCO has reached the following findings:

- There are no options available to address the 5/30 issue in isolation which provide a net positive benefit to the NEM with respect to market efficiency. Non-quantified and qualitative costs and benefits are not considered to be of sufficient magnitude or certainty to offset the excess of quantified costs over quantified benefits. As such, NEMMCO concludes that it has not identified grounds to propose changes to the existing NEM arrangements.

- The “No Change” option is therefore recommended by NEMMCO.

NEMMCO considers that the market efficiency aspects of the 5/30 issue have now been investigated in detail, and subject to comments received in respect of this draft report, does not propose to further consider the matter in the foreseeable future.

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1 Introduction

This paper presents the findings of NEMMCO's investigation into resolving the 5 minute dispatch and 30 minute settlement (5/30) anomaly in the National Electricity Market (NEM). A previous NEMMCO investigation into this issue during 2000 concluded that the 5/30 issue was material to some NEM participants and recommended further work to investigate ways to address the issue.

This latest 5/30 work stream commenced in April 2001 and has included a detailed investigation by an industry working group into options to address the 5/30 issue, and a cost benefit analysis of the preferred options. The investigation concludes with the findings contained in this report.

The 5/30 Issue:
The NEM uses a 5 minute dispatch interval which produces dispatch targets for generators and scheduled loads, and a cleared marginal spot price for each 5 minute dispatch interval. Settlement of the energy market however, takes place using a 30 minute pricing interval, where the price is calculated as the average of the 5 minute dispatch prices.. This aspect of the NEM, and the ramifications emerging from it, have been referred to as the "5/30 Issue".

2 Context and Structure of this paper

Context

It is important that this report is read in conjunction with the supporting documents[3]. Those document provide background information on the 5/30 Issue, the context and scope of this project work stream, NEMMCO objectives and considerations and output from both the 5/30 Working Group and the consultant engaged to assist with the cost / benefit analysis.

Structure

This report is broken into a number of sections in order to present a structured overview of the 5/30 issue itself, the working group process, details of the options identified, the analysis that was undertaken for each option as well as the results of the analysis and recommendations.

In particular, there are sections that cover in detail the following key information:

- A description of the 5/30 issue as well as worked examples as to how it may impact different NEM participant groups;
- The working group process, detailing the history of how the options came to arise;
- The cost/benefit framework used to assess the options;
- Details of the consultant engaged to assist NEMMCO determine market benefits for each option;
- Details of the costs and benefits (in terms of market efficiency) and the Net Benefit for each option; and,
- Conclusions of the consultant, NEMMCO and NEMMCO's recommendations.

A number of appendices to this paper are referenced in sections of the main text body and provide further detail in the following areas:

- Examples of the 5/30 Issue;
- Detailed Description of the Preferred Options;
- Costs Of Preferred Options;
- Benefits Of Preferred Options;
- Application of NEMMCO's "Draft Efficiency Guidelines" to this project;
- Description of the 30 Minute Option.

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3 Supporting documents are referenced after the recommendation section of this report and include the following documents:
- Project Outline and Terms of Reference;
- Issue Definition Paper;
- Options Paper;
- MMA Issues Paper;
- MMA Final Report; and,
- NEMMCO Draft Efficiency Guidelines.

3 Background

NEMMCO acknowledges the anomaly that exists between 5 minute dispatch interval and 30 minute average pricing has created issues for some market participants.

In particular, participants who can effectively respond to five minute price signals face limited market opportunities under the current market arrangements in regard to some of the physical capabilities of their assets. Examples of these participants include hydro generators, fast start generators and market network service providers (MNSPs).

This situation occurs, for example, when a high cost, fast start generator is dispatched to respond to a 5 minute high price spike, yet only receives payment on a lower half hourly average price. Alternatively a fast response load may not respond to short term price signals due to the reduced incentive of a lower 30 minute average price used for settlements.

This aspect of the NEM design received attention as early as 1997 when the ACCC noted in a report on the Application for Authorisation of the National Electricity Code (ACCC 1997-a) that high cost and fast start generators were particularly concerned by this aspect of the market design. It was recognised by the ACCC that those participants were affected by the 30 minute average pricing design which entails a degree of (inadvertent) dampening to price volatility in the market.

NECA also recognised that the anomaly has a significant impact on peaking generators (NECA 1999-a) and stated further, that the current design does not provide equal opportunity to some peak load participants.

The anomaly was also acknowledged in the NECA Capacity Mechanisms Review – Final Report (NECA 1999-b) and that the current dispatch and pricing interval design represents a compromise position between a longer interval approach which would result in a greater reliance on ancillary services, and a shorter period which would be likely to push the limits of current technology. In that report, NECA endorsed further development work on this issue.

The Reliability Panel considered the 30 minute average pricing to have adverse effects for the market. The Reliability Panel has also urged that the matter be resolved prior to its review of VoLL in the NEM (NECA 1999-c).

NEMMCO has performed initial work to review the 5/30 anomaly. The NEMMCO sponsored Dispatch and Pricing Reference Group (DPRG) (NEMMCO 1999-d) discussed the anomaly that can exist between the dispatch cycle and the trading cycle. While the averaging process can filter out some of the inherent volatility in a 5-minute dispatch cycle, it can also create distortions and inefficiencies in the market due to dampening price signals and inconsistencies between pricing and dispatch.

The averaging process limits a fast start generators' ability to offer price reflective hedging products to the market which manage short term price spikes and consequently reduces market efficiency by increasing the cost of hedging to market participants and results in higher pass through costs to customers. Price responsive demand side participants are also faced with a reduced incentive to respond to high price spikes and invest in advanced load management systems – responses which their plant is physically capable of delivering.

NEMMCO's most recent consultation paper (NEMMCO 2001-a) on the 5/30 issue recommended further more specific investigation to determine the merits of changing the market design in the medium term, in coordination with changes to VoLL and the second phase of the ancillary services review recommendations.

The 5/30 Working Group was formed by NEMMCO in April 2001 to complete this more detailed investigation work. This report presents the findings of that work. The project outline and terms of reference issued to guide the scope of the working group may be found on the NEMMCO website .

Membership and structure of the 5/30 working group is contained in Appendix 1.

4 The Working Group Process

The working group process ensured that a full spectrum of NEM participant views were included in the analysis of the 5/30 issue. Working group members, being representatives of a NEM sector, were also responsible for ensuring that their fellow NEM participants were kept informed of developments throughout the project. The study undertaken by the working group involved the following stages:

1. Develop a group understanding of the impact of the issue on various NEM participants;

2. Confirm the materiality of the issue by attempting to quantify the issue for the NEM;

3. Develop an Issue Definition Paper[4] to articulate the scope of the 5/30 issue;

4. Investigate options to address the issue. Develop a criteria to perform an initial evaluation of the potential options with that aim of identifying a preferred option for detailed evaluation. (This resulted in two options submitted for detailed evaluation);

5. Perform a detailed cost benefit analysis of the preferred option. The working group members identified the net costs associated with each option for their respective sector of the market. (eg NGF representatives on the working group identified the net costs for the total generator sector, NRF representatives identified the net costs for all retailers etc);

6. Assist the consultant engaged by NEMMCO as required to understand the 5/30 Issue and develop an Issues Paper [5] indicating the methodology to be used by the consultant to identify market benefits in terms of improved market efficiency. This included developing an understanding of NEM participant behavioural changes that would occur in moving from the current NEM arrangements to the dispatch and settlement regimes for each option.

7. Assistance to NEMMCO and the consultant throughout the evaluation stage .

The working group notes:

- Further detailed analysis during the evaluation stage led both NEMMCO and the working group (including retailer representatives) to believe that one of the two recommended options (Option 2.2) was, in fact, not desirable. The option had been submitted for

[4] Issue Definition Paper

5/30 Working Group 2001a, 5/30 Minute Issue Definition, 5/30 Working Group, September 2001. (URL http://www.nemmco.com.au/future/design/1182.htm)

[5] MMA Issues Paper

McLennan Magasanik Associates 2002a, Issues Paper: Modelling of the Efficiency Gains from Resolution of 5/30 Issue, McLennan Magasanik Associates, 28 January 2002. (URL http://www.nemmco.com.au/future/design/1182.htm) detailed evaluation by this stage. This issue is discussed further in the NEMMCO conclusions section.

- Interest was also expressed during working group discussions in the “30 minute dispatch and 30 minute settlement option” which is detailed in the 5/30 working group’s Options Paper[6] as well as Appendix 6. This option was not considered appropriate to address the 5/30 issue in isolation as detailed consideration of this option would be far bigger than the 5/30 issue itself as it would require review of many parts of the NEM design. Significant costs associated with this option would eliminate it for consideration in regard to the 5/30 issue in isolation. Evaluation of the option was therefore not attempted by the working group.

[6] Options Paper: 5/30 Working Group 2001b, Options for resolving the 5 Minute Dispatch and 30 Minute Settlement Anomaly in the NEM, 5/30 Working Group, September 2001. (URL http://www.nemmco.com.au/future/design/1182.htm)

5 Working group quantitative analysis

The working group performed a historical analysis of NEM price outcomes by examining the results of a comparison between the existing settlement arrangements and a full 5 minute settlement regime. The results indicated that the difference between NEM settlements regimes over a period of a two month historical sample was quite small (0.015% of the value of settlements). The two month sample period was selected during summer (January 2001 – February 2001) to gain an appreciation of a worst case example. This low result was not unexpected by the working group members as they believed that NEM participants modify their market behaviours to the prevailing dispatch and settlement conditions.

6 Description of 5/30 Issue

This section describes the basis of the 5/30 issue by reviewing the three areas in which the 5/30 issue impacts the NEM and its participants, namely;

- Spot Market Issues;
- Ancillary Services versus Energy Market Reserve Issues; and,
- Contract Market Implications.

a) Spot Market Issues

The NEM uses a 5 minute dispatch interval which produces dispatch targets for generators and scheduled loads, and a cleared marginal spot price for each 5 minute dispatch interval. Settlement, however, takes place using a 30 minute pricing interval which is calculated as the average of the 5 minute dispatch prices to settle the energy market for the 30 minute trading interval.

Example: The 30 minute trading interval price used for settlement is the simple (or "time weighted") average of the 5 minute dispatch prices.

Dispatch Interval (minutes)	**5**	**10**	**15**	**20**	**25**	**30**
Dispatch Price ($/MWh)	40	40	**10,000**	40	40	40

5 minute Price Spike

Trading interval price is calculated as the time weighted average of the dispatch prices = $1,700.00 /MWh.

This aspect of the NEM structure produces a disparity between price and dispatch, in particular:

- Settlement on the basis of average 5 minute prices across the half hour means that prices are a hybrid of ex-ante and ex-post characteristics. Whilst the ex-ante 5 minute prices aim to signal market conditions to participants to elicit immediate responses, the price at which the market is settled is not firm until near the end of the half hour (the 25th minute) – likely to be well after the need for response for the trading interval has passed.

  This latter ex-post characteristic means that NEM spot prices do not provide a reliable or FIRM "avoidable cost " to participants on either side of the market. Demand side participants do not have a clear incentive to respond to short periods of high price because they do not know the final price until after the event; and similarly, generators that could generate in response to short periods of high prices do not know whether the price will remain high until afterwards. **The key issue here is that existing NEM arrangements manifest a reduced incentive for fast response plant and demand side management to respond to spot prices in the short term.**

- Settlement on the basis of half hourly average prices also creates an inherent inconsistency between dispatch and settlements. Generators (or demand side participants exposed in some way to spot prices) may be in a position to respond to the 5 minute dispatch prices and associated dispatch targets issued in the spot market, but may be settled at a value that is quite different from that implied by their firm bids, offers or voluntary responses in the case of non-scheduled participants.

  In some examples, this disadvantages the participant financially:
  - Price responsive plant – see Appendix 2 Example 1; and,
  - MNSPs – see Appendix 2 Example 4.

  In some other cases, the participant is advantaged by the process:
  - Generator trip – see Appendix 2 Example 2; and,
  - MNSP dispatch – see Appendix 2 Example 3).

  In all of these cases however, the incentive to respond to the dispatch and pricing outcomes in the market is confused to some degree, and arguably to the disadvantage of the market as a whole in each case. The market may be burdened by an inefficient increase in the cost of hedging through the application of conservative premiums by hedge sellers in order to address this additional risk. This may result in increased prices for caps or higher offer prices from generators.

  The key point here is that response to 5 minute dispatch and pricing outcomes is often not reflected in NEM settlement outcomes, thus corrupting the market signals arising from the dispatch and pricing process.

b) Ancillary Services versus Energy Market Reserve Issues

Operating reserves in the NEM are provided through frequency control ancillary services with response rates of 6 seconds, 60 seconds and 5 minutes and also by plant offered at a price just above the prevailing energy market dispatch price. Specific ancillary service payments are made for plant presenting as an ancillary service.

Energy market incentives are currently relied upon to ensure adequate operating reserve is available beyond the 5 minute ancillary service boundary. Reserve margins, for example, the largest unit in the region, have been set to meet the overall reliability standard established by the Reliability Panel. NEMMCO may intervene in the market to ensure these margins are maintained. Current practice is for NEMMCO to assess reserves that can be realised within 30 minutes. In many cases plant providing ancillary services capability can maintain output beyond the period needed to manage power system frequency and thus can contribute to energy market reserve. This is not necessarily the case however. In the extreme, all ancillary service capability may be exhausted after 5 minutes and other reserve in the energy market may not be physically available for 10 to 20 minutes. This might be the case in a region where all reserve at the time was being provided from gas turbines and arises as a consequence of the start up times of the plant.

It is however, unusual for a region of the NEM to be entirely dependent on local generating plant with start up times in the range 5 to 30 minutes. Typically, reserve would be available from plant already synchronised but not fully loaded and or overload capability on interconnectors providing access to capacity in other regions, except at times of supply shortage. **The key point here is that in order for market mechanisms to deliver reserves in the sub half hour regime, price signals in that regime need to be consistent with the services that need to be delivered.**

c) Contract Market Implications

For the market as a whole to operate efficiently, it is important that wholesale generators and customers are not hindered from entering into forward trading and financial risk management instruments to manage their commercial positions. In this regard, generators typically offer to the market financial hedging instruments that are settled in a timeframe consistent with the NEMMCO half hourly settlement.

The key issue here is that financial hedging instruments are written on the basis of an underlying commodity price using standard financial market conventions. At present the underlying commodity price for electricity is the half hourly regional pool prices published by NEMMCO.

Hedging to protect against price movements within the 30 minute trading interval may currently be inefficient compared to hedging on a basis consistent with the short term price signals (ie 5 minutes) due to the additional risk introduced to the hedge seller by the 5/30 issue and the resultant uplift in hedge price in the form of an estimated premium.

7 Identification of options to address the 5/30 Issue

The 5/30 working group aimed to develop a detailed understanding of the 5/30 issue and its impacts, then sought to identify potential options to address Issue.

Options

A total of eight options as well as the “no change” scenario were identified as candidates by the working group. An important option is the “No Change” default scenario as this is the basis against which each option was ultimately compared.

The working group identified key components of the existing NEM arrangements that are impacted by the 5/30 Issue. These components include the dispatch and settlement periods, the pool price calculation methodology and the range of coverage of ancillary services over the 30 minute NEM settlement period. The working group examined how each of these components was impacted by the 5/30 issue and then progressed to identify two broad areas under which potential options were sourced in addition to the “no change” scenario, namely:

- Aligning the energy market dispatch and settlement periods; and,
- Modify the energy market pricing/settlement methodology.

An Options Paper[7] was published in October 2001 by the Working Group which described the eight identified options as well as the reference “no change” scenario. The options description paper was published at that time to inform market stakeholders of the status of the group’s work, and to ensure that opportunities for input to the project via working group members was maximised.

The working group developed and applied an assessment criteria to evaluate each option so that one option could be identified to be put through a detailed cost / benefit evaluation. The working group identified one preferred option for detailed cost / benefit evaluation (Option 1.1(b) – 5 minute dispatch and Simulated 5 minute settlement). The NRF representatives also expressed strong desire for a second option to be evaluated due to its perceived low costs for retailers (Option 2.2 Hybrid demand weighted option). The evaluation therefore compared both options relative to the “no change” scenario.

More detailed analysis during the evaluation stage led both NEMMCO and the retailer representatives to believe that the retailer supported option (Option 2.2) was not desirable. This was due to complications in the following areas:

- financial markets trading difficulties due to different prices for the supply and demand sides of the NEM;

[7] Options Paper: 5/30 Working Group 2001b, *Options for resolving the 5 Minute Dispatch and 30 Minute Settlement Anomaly in the NEM*, 5/30 Working Group, September 2001. (URL http://www.nemmco.com.au/future/design/1182.htm)

- mandatory 5 minute interval metering for generators, interconnectors and MNSPs; and in particular,

- the necessity to produce trading interval prices estimates in real time on the basis of SCADA data approximations, followed by the revision of all trading interval prices at the end of each week to balance settlements when 5 minute interval meter data becomes available.

8 Description of preferred options

Detailed descriptions for the two preferred options are contained in Appendix 2.

In brief summary, both option address the 5/30 issue with similar overall outcomes for generators and MNSPs in that their final settled spot market revenues for energy as well as other services (in total aggregate) are equivalent to those that would be expected under an aligned 5 minute dispatch and settlement regime.

Market customers, however, are treated differently by the two options:

- Option 1.1(b) allows market participants to optionally participate in the same regime as that for generators with remaining customers being grouped, with settlement imbalances recovered from this grouping. It would not be expected that many market customers would take this option due to metering issues involved - hence this option would be less effective at increasing the incentives for demand side participation. A simple after market settlement adjustment is applied to restore revenues to account for the 5/30 issue;

- Option 2.2 introduces a volume weighted regional reference price regime which treats all customers equally. It also diminishes any incentive for demand side management at an individual market customer level. This option also introduces price asymmetry between generators and customers and necessarily involves publishing estimates for dispatch purposes and then publishing revised final prices for all dispatch intervals for the previous week in accordance with the settlement cycle (ie revising all prices for the previous week). Mandatory 5 minute interval metering is also required for generators, MNSPs and interconnectors.

The specific differences between these options result in both different costs and benefits to addressing the 5/30 issue.

9 Cost/benefit analysis framework

In accordance with NEMMCO's objective under Clause 1.6.2(b) of the National Electricity Code, the options for change were evaluated in terms of their potential impact on the efficiency of the market.

NEMMCO utilised a cost benefit framework that enabled a determination to be made as to which option, if any, provided the greatest net positive benefit to the market in terms of improved market efficiency. This efficiency overview was presented in the Terms of Reference[8] for the 5/30 working group . An interpretation of market efficiency is discussed in the following section.

[8] Project Outline and Terms Of Reference: NEMMCO 2001b, 5/30 Minute Working Group - Project Outline and Terms Of Reference, NEMMCO, March 2001. (URL http://www.nemmco.com.au/future/design/1182.htm)

10 Market Efficiency

10.1 Defining Efficiency

NEMMCO engaged McLennan Magasanik Associates (MMA) to perform economic analysis and quantitative modelling for the 5/30 issue.

Before commencing any detailed modelling work, MMA produced an Issues Paper[9] which discussed the economic notion of market efficiency from a practical perspective, as well as their proposed methodology to quantify efficiency gains. This issues paper was discussed with the working group and refined as a first step. Following consolidation of their issues paper, MMA proceeded to carry out modelling work over a number of months, leading to the production of a final report which presents their findings.

Three types of efficiency gains are described by MMA in its issues paper and final report, with the description of the efficiency gains expressed by MMA as follows:

<u>Productive efficiency</u>: *Productive efficiency occurs when the least cost combination of inputs is being used to produce a given level of output. In the wholesale electricity market, it implies that the least cost plants are being dispatched to supply demand. Critics of current settlement arrangements argue that they result in inefficient dispatch of plant either through high cost plant being dispatched ahead of other plant in the post spike dispatch intervals or hydro-electric generation not being used optimally.*

<u>Allocative efficiency</u>: *Allocative inefficiency occurs where prices do not equal marginal costs because of the exercise of market power or through the price setting process. By discouraging the dispatch of some fast ramp plant or demand side management (DSM) from the market, the current settlement arrangements may prevent allocative efficiency. Greater commitment of either option may increase the intensity of competition in the market for fast ramping plant.*

<u>Dynamic efficiency</u>: *Where the least cost options for electricity supply are encouraged to enter the market over time. In respect of the 5/30 issue, concern has been raised that the current NEM arrangements may result in inadequate returns to encourage entry of fast ramping options, resulting in new entrant generation of a type that is not optimal. By resolving the 5/30 issue, other fast ramp options may be better encouraged to enter the market - including fast ramp peaking plant; new dispatchable loads; and enhancements to the ramp rates of existing plant.*

It should be strongly noted that options to address the 5/30 issue result in wealth transfers from some NEM participants to others when changes are proposed to dispatch and

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9 *"Issues Paper: Modelling of the Efficiency Gains from Resolution of 5/30 Issue", McLennan Magasanik Associates, 28 January 2002.*

settlements regimes (for example transfers may occur from customers to peaking generators). These wealth transfers do not necessarily represent market efficiency gains and have been considered by MMA on a case by case basis. Wealth transfers that do not represent efficiency gains to the market are not used by NEMMCO to justify changes to the NEM. The issue of transfers and identifying market efficiency gains are explained in greater detail in section 3 of MMA's Final Report.

MMA identified the potential areas in which NEM efficiency gains may be derived by resolving the 5/30 issue prior to their quantitative modelling. The following table shows each efficiency gain area as well as the type of efficiency gain in accordance with the above efficiency definitions:

Table 1: Efficiency gains from resolving the 5/30 Issue

Efficiency Gains	Efficiency Type
1. Avoiding the dispatch of high cost generators ahead of low cost generators	Productive efficiency
2. The opportunity cost of hydro generation	Allocative efficiency
3. Increased dispatch of demand side bids	Allocative efficiency
4. Increased inter-regional flows on MNSPs	Allocative efficiency
5. Dynamic efficiency gains (better investment occurs in plant mix over time)	Dynamic efficiency
6. Higher premiums on financial market caps	Allocative efficiency

10.2 Defining Efficiency

In economic terms, an efficient process is one that maximises output for a given input and/or minimises input for a given output – or to put it another way, the collective benefits to consumers and producers (the 'pie') are made as big as possible. Consistent with this interpretation, NEMMCO is seeking to ensue that, where efficiency is the criterion, proposals recommended for implementation will be ones that make the market more efficient (or 'the pie bigger').

11 MMA quantitative modelling

MMA employed a monte carlo type simulation model of the NEM in order to analyse the two preferred options with reference to the no change scenario over a study period of ten years. The modelling was performed using the IES Software “Prophet” which was set up to enable simulation of the NEM to a resolution of 5 minutes.

An analysis framework was used by MMA that incorporates the modelling of not only the physical aspects of the NEM but also looked at participant behaviour under various market situations. Working group members assisted MMA in structuring appropriate participant behavioural response changes in moving from the current NEM arrangements to the new arrangements applicable for each option. The strategies were incorporated in the model through a process that optimises the offers submitted by a participant for a particular dispatch interval based on the prevailing market conditions.

This feature of MMA’s analysis was considered to be important by the working group in capturing the changes in market efficiency between options as participants would exhibit different market behaviours under different dispatch and settlement regimes.

Detailed descriptions of the modelling work undertaken as well as the model data and NEM structural and regulatory assumptions are detailed in section 3.2 of MMA’s Final Report.

12 Scope and limitations of the analysis

All quantitative modelling methods have different advantages, disadvantages, inherent assumptions and limitations. The physical complexity of the NEM also presents challenges to modellers in that there is always a temptation for observers to compare forecast results with actual outcomes, and such approaches will always show differences due to specific plant events in the NEM and other specific influences and externalities such as the weather changing demand forecasts.

MMA's monte carlo simulation approach enables different market outcomes to be observed in each simulation run. With an infinite number of simulation runs, this type of model should eventually produce all possible market outcomes (ie all states for all model variables). The model produces probabilistic outcomes in that each possible model variable, such a specific generator failure, is assigned a probability of occurring in any given time period. The model therefore produces a distribution of outcomes and for reporting purposes, the average, or most probable outcome scenario is used.

The use of average outcomes recognises that there is a possibility that actual price outcomes for example, in any particular period could be less than the average (by definition) and that it is equally possible for prices to be above the average. MMA believes that utilising the average price outcomes from this modelling methodology to determine the benefits applicable to the 5/30 issues over a study timeframe of ten years is the best approach and that the aggregate benefits are most likely to be captured. NEMMCO agrees with this conclusion.

MMA performed calibration testing of their model to confirm that price outcomes were consistent with those over a one-year historical period (2001). Test results showed that modelled price spikes agreed with actual NEM prices to within 3% and the error in average prices for each state was no more than 40 cents. Specific differences in this calibration would be attributable to actual NEM events (eg plant failure) during 2001 compared to the probabilistic averages for those events. This provides some confirmation that the modelling can produce reasonable price outcomes.

Other modelling assumptions including load growth, introduction of known generation plant projects and interconnector projects are detailed in Appendix A of MMA's final report.

13 Results

The results from the quantitative assessment for both options have been shown in this section in terms of costs, benefits applicable to efficiency gains and finally the net benefit to the market (positive or negative) from each option.

13.1 Cost Estimates

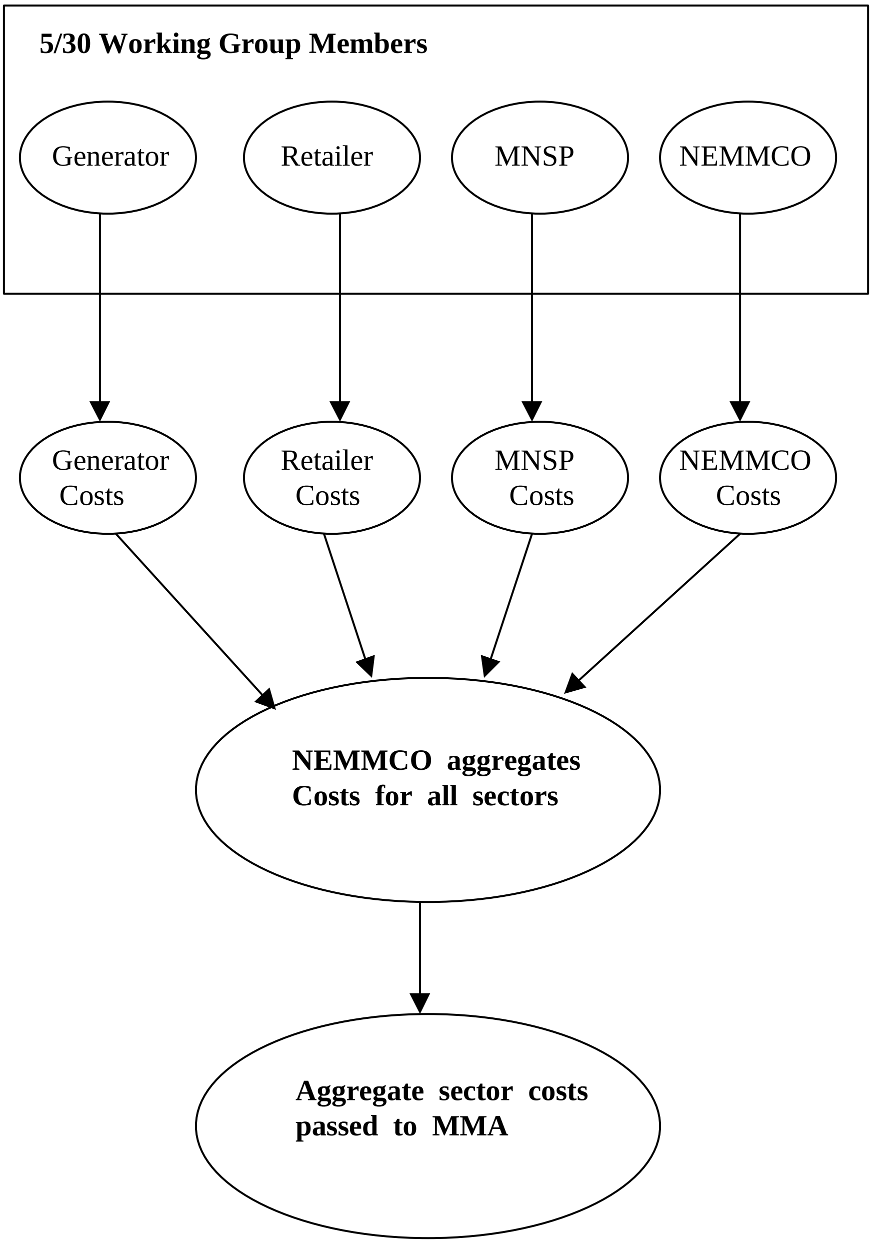
The costs of implementing the preferred options, both up-front costs and ongoing annual costs, were identified and estimated for each industry sector by the representatives on the 5/30 Working Group for their respective industry sectors. The Fig 1 shows a generic diagram illustrating the methodology used to estimate the costs for each option.

Cost estimates for the retail sector were the most time consuming to obtain due to the need for a full cost estimate survey. The retailer representatives on the working group expressed concerns that the costs may vary from one retailer to the next due to differences in IT systems configuration and sophistication as well as whether or not the retailer incorporated a network business.

To address these concerns, itemised cost estimates for a typical retailer business were prepared by the retailer working group members and these were circulated to all retailers via the National Retailers Forum (NRF) in the form of a cost estimate survey. Individual retailers expressed concerns that disclosing the individual cost estimates in the survey could in some way release commercial information to the retailer working group members. NEMMCO agreed to act as the recipient of the individual survey responses (in confidence) and to then aggregate the retailer costs before forwarding the aggregate cost estimates to MMA (together with the other sector costs) for inclusion in the Net Benefit calculation. In this way, commercially sensitive cost information would be jeopardised.

NEMMCO has accepted the cost estimates from each industry sector at face value. NEMMCO did however, pay close attention in understanding the costing estimates from retailer sector because these costs made up more than 95% of costs for option 1.1(b) and 46% of costs for option 2.2. The retail sector also faced more than 90% of the ongoing costs for the options. The process for collation of retailer cost data included requests for more detailed descriptions of itemised retailer cost elements and in some cases re-verification of individual cost items at NEMMCO’s request. This process resulted in a number of revised retailer cost estimates prior to final submission of the aggregate costs data to MMA.

Figure 1. Estimating Costs for the options to address the 5/30 issue



13.2 Summary of Option Cost Estimates

Table 2 shows a summary of the aggregate NEM upfront and annual costs identified by industry representatives for each option. These costs are then brought forward to a net present value in mid 2002 dollars. The majority of costs are incurred in the retailer sector of the NEM and the majority of costs are attributed to necessary IT systems enhancements.

Table 2: Implementation and ongoing costs, $M, mid 2002 dollar terms. NPV shown at 7% discount rate.

	NPV	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Option 1.1(b)	**160.2**	74.4	13.8	13.8	13.8	13.8	13.8	13.8	13.8	13.8	13.8	13.8
Option 2.2	**54.5**	32.3	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7

Clearly, both options result in significant costs to the NEM, with option 1.1(b) having significantly greater costs due to both higher up front costs and significantly higher ongoing costs.

Further information regarding cost estimates and costing breakdown by industry sectors is included in Appendix A4.

13.3 Summary of Benefits

MMA utilised its skills in both economics and quantitative modelling to derive the efficiency benefits for each option relative to the reference "no change" scenario over a ten year study period. The methodology for MMA's approach is detailed in MMA's Issues Paper with the final results detailed in the Final Report .

Real efficiency gains to the NEM derived by resolving the 5/30 issue were found by MMA to reside in the following areas:

- Avoiding the dispatch of high cost generators ahead of low cost generators;
- Ensuring optimal use of fast response hydro generation as determined by its opportunity cost at any point in time;
- Increased dispatch of demand side bids;
- Increased inter-regional flows on MNSPs;
- Dynamic efficiency gains (plant mix); and,
- Reduced premiums on financial market caps.

In deriving benefits applicable for each option, MMA tested the robustness of its analysis against four scenarios.

MMA also performed sensitivity analyses against the following two variables:
- discount rate or Internal Rate of Return (IRR); and,
- period (duration) of the study.

The four scenarios studied include the following:
- a most probable "Medium Scenario";
- a high demand growth rate "High Scenario";
- a study to consider the case that Basslink does not proceed "No Basslink"; and
- a scenario where the market cycles between over supply and under supply of generation to satisfy demand "Cycling".

The market benefits are shown in the table below for each scenario as well as the combinations of sensitivities to discount rate and study period.

Table 3: Net present value of the market benefits, $M, mid 2002 dollar terms.

Scenario	7% IRR, 10 Years	7% IRR, 15 Years	10% IRR, 10 Years	10% IRR, 15 Years
Medium	28.8	34.0	26.1	29.7
No Basslink	36.2	42.5	32.7	37.1
Cycling	39.5	47.4	35.6	41.1
High	48.9	57.9	43.8	50.1

13.4 Net Benefits to the market

In order to determine whether to proceed with a recommendation to implement an option to address the 5/30 issue, NEMMCO must ensure that the efficiency benefits that are gained from making changes to the NEM will more than offset the costs to the market by some margin of confidence.

The costs of implementation (as derived by the Working Group and provided to MMA by NEMMCO) have been deducted by MMA from the benefits identified for each option to produce a total net benefit (positive or negative) for each option. The following tables show the net present value of the Net Benefits for each option including the sensitivities for discount rates and period of the study:

<u>Option 1.1(b)</u>

Table 4: NPV of Benefits and Costs for Option 1.1b, mid 2002 dollar terms, $M

	7% IRR, 10 Years	7% IRR, 15 Years	10% IRR, 10 Years	10% IRR, 15 Years
Market Benefits				
Medium	**28.8**	34.0	26.1	29.7
No Basslink	**36.2**	42.5	32.7	37.1
Cycling	**39.5**	47.4	35.6	41.1
High	**48.9**	57.9	43.8	50.1
Costs	**160.2**	187.0	144.8	163.1

	7% IRR, 10 Years	7% IRR, 15 Years	10% IRR, 10 Years	10% IRR, 15 Years
Net Benefits				
Medium	**-131.3**	-153.1	-118.7	-133.4
No Basslink	**-124.0**	-144.5	-112.1	-126.0
Cycling	**-120.6**	-139.6	-109.2	-122.0
High	**-111.3**	-129.1	-101.0	-113.0

Clearly, Option 1.1(b) does not provide a net positive benefit under any of the four scenarios modelled and this result is robust in relation to both sensitivities for discount factor and period of study.

Option 2.2

Table 5: NPV of Benefits and Costs for Option 2.2, mid 2002 dollar terms, $M

	7% IRR, 10 Years	7% IRR, 15 Years	10% IRR, 10 Years	10% IRR, 15 Years
Market Benefits				
Medium	**27.4**	32.3	24.8	28.3
No Basslink	**32.8**	38.9	29.6	33.9
Cycling	**36.9**	44.5	33.3	38.7
High	**45.0**	53.5	40.5	46.4
Costs	**54.4**	61.7	50.0	54.9
Net Benefits				
Medium	**-27.0**	-29.4	-25.2	-26.6
No Basslink	**-21.6**	-22.8	-20.4	-21.0
Cycling	**-17.5**	-17.2	-16.7	-16.2
High	**-9.4**	-8.2	-9.5	-8.5

Again, Option 2.2 falls considerably short of providing a net positive benefit under any scenario modelled and again the result is robust in relation to both sensitivities.

Market benefits for both options would need to significantly improve or alternatively the costs drop substantially in order for either of the options to even meet costs from a market efficiency perspective.

Total net benefits are discussed in further detail in the conclusion section.

14 Conclusions

NEMMCO has conducted two sequential investigations into the 5 minute dispatch and 30 minute settlement anomaly. The first investigation described the issue, considered the affected NEM participants and came to the conclusion that further investigation was warranted into ways to address the 5/30 issue. The most recent investigation, which is the subject of this report, identified potential options to address the issue with the assistance of an industry working group and then with the assistance of MMA, performed a detailed benefit / cost analysis of the preferred options.

NEMMCO remains unbiased in its intention for any desired outcome from this investigation, other than to pursue improved market efficiency, as it is a neutral party in the NEM settlement process.

NEMMCO believes that the working group members have thoroughly considered the issue during an interactive and effective working group process and the members have worked closely with MMA at all stages during their investigations and analysis.

Key Observation:

The cost benefit analysis has indicated that the benefits to be gained from resolving the 5/30 issue, in terms of market efficiency, DO NOT outweigh the costs to the market involved in adopting either option.

Key Observation:

The analysis of the 5/30 working group has shown that the 5/30 issue clearly affects a number of NEM participants and that real and material market efficiency benefits have been identified by MMA as being accessible should the 5/30 issue be resolved. However, the investigations performed by the 5/30 working group and MMA have shown that;

- **The costs involved in implementing options to address the 5/30 issue are greater than the benefits in efficiency to the NEM; and therefore,**
- **A positive net benefit in terms of gains to market efficiency has not been identified through any option.**

Financial Transfer Payments (distribution payments)

MMA has indicated in its final report that resolving the 5/30 issue by implementing either of the options modelled will result in changes to settlement distribution payments which are effectively financial transfer payments from some categories of market participant to others. These do not represent efficiency gains in the market but are instead transfers of wealth in the economic sense.

It is seen by some participants that these financial transfer payments are the means by which restoration of appropriate price signalling in the NEM would be achieved if the 5/30 issue were addressed by one of the options. In accordance with NEMMCO's objective to improve market efficiency, however, this effect does not provide a basis for NEMMCO to recommend changes to the market, particularly where evidence of a net efficiency gain has not been established.

As noted in Section 10.2, where efficiency is the criterion, NEMMCO's focus is to ensure "the pie" gets bigger. Where the impact of change is purely a financial transfer from one market participant to another, there is no impact on the size of the pie, there is merely a change in who gets what slice of the pie – the market is neither more nor less efficient than before.

MMA Conclusions

MMA's conclusions were summarised in their final report as follows:

- *The benefits of aligning settlement and dispatch prices are unlikely to exceed the costs. Market benefits are low principally due to the low level of incidence of price spikes in the market principally as a result of a surplus of generation capacity over the next few years.*

- *The costs of proposed options for change are high, principally due to the high set up costs incurred by market customers. The costs exceed the benefits especially for Option 1.1(b). A large reduction in the costs would be required for there to be positive net benefits.*

- *As costs exceed benefits, the "no change" option is the preferred outcome. Of the two alternative options considered, Option 2.2 has the higher net benefit (or lower net loss) even though the market benefits are higher for the other option.*

MMA also noted that the outcomes of the analysis may be impacted if:

- the supply/demand balance were to significantly change; or

- option implementation costs were significantly reduced if, for example, other market changes warranted similar IT system changes and some 5/30 issue costs were absorbed; or,

- the number of NEM retailer businesses were rationalised over time.

NEMMCO Conclusions

As established in the outset of this project, in order for NEMMCO to initiate a proposal to change the market arrangements to address the 5/30 issue, clear evidence of net gains in market efficiency would be required. Furthermore, some margin of benefits over costs would be needed to ensure the conclusion is robust against variations in modelling scenarios. The net benefits to the market of any option were found to be substantially negative and therefore do not support NEMMCO initiating a proposal to change the NEM to address the 5/30 issue.

NEMMCO acknowledges the views expressed to date by parties promoting changes aimed at solving the 5/30 issue and has to this point allocated significant resources to investigate the issue. Industry representatives have also dedicated significant resources in supporting NEMMCO's 5/30 issue investigation. On the basis of the analysis performed in this project, a proportion of the impact arising from the 5/30 issue and its resolution lie in the allocation of financial transfer payments[10] rather than in efficiency impacts. NEMMCO does not consider it is in a position to promote change on those grounds alone, particularly in view of the finding that a net industry cost is likely to be incurred in proceeding with any such change. Nevertheless, NEMMCO acknowledges that these transfers may be significant to the stakeholders concerned, and that they may wish to pursue change with parties that are in a position to apply broader criteria to the assessment than NEMMCO.

It should be noted that **Option 2.2 is now not considered to be acceptable**. Further detailed analysis during the evaluation stage on settlement implications has led both NEMMCO and the working group (including the retailer representatives who originally supported Option 2.2) to believe that this option is not desirable and would, in fact, create serious issues in the NEM. This was due to complications with the option in the following areas:

- financial markets trading difficulties due to effectively different prices being seen for the supply and demand sides of the NEM due to the volume weighting methodology being different for generators and market customers. Divergent views would then arise as to the structure of appropriate hedge contracts;

- mandatory 5 minute interval metering for generators, interconnectors and MNSPs in order to achieve balanced settlements; and in particular,

- the necessity to produce trading interval price estimates in real time with all trading interval prices requiring revision at the end of each week to balance settlements when 5 minute interval meter data becomes available. SCADA data would be required to produce the interim trading interval prices.

The last issue represents a real threat to the reliability and credibility of published trading interval prices and may therefore have the potential to undermine confidence in the NEM pricing process. For these reasons, NEMMCO would not support Option 2.2.

Non-quantified costs and benefits

A distinction can be made between "non-quantified" and "non-quantifiable" factors:

[10] Distribution payments (or transfer payments) as described by MMA in their final report.

- **non-quantified factors** would be those things that could (with some effort) be numerically assessed, but because the effort is considered unwarranted, no formal numerical estimate is made;

- **non-quantifiable (or qualitative) factors** are be those things that are unable to be numerically assessed even if detailed assessment was desired.

Non-quantified and non-quantifiable (qualitative) costs and benefits have been considered by the consultant in the analysis. Non-quantified and qualitatively assessed costs are identified in Appendix 4 of this document and include a number of items containing second order or lesser costs ($'000 rather than $M). The non-quantified (but potentially quantifiable) costs were an order of magnitude less than more prominent quantified cost areas. NEMMCO does not believe that these costs make a material impact on the net outcome for either option.

The magnitude of benefits to be yielded from non-quantified and qualitative factors are more difficult to establish. However, the consultant has identified and qualitatively assessed a number of items in the financial markets area that may deliver some benefits. In the opinion of the consultant, these speculative or potential benefits were not capable of being quantified with any level of accuracy. MMA identified areas where benefits from the options may be difficult to quantify in section 3.2.3 of it's final report. MMA explained that these benefits lie in the area of "changes to the market for financial contracts". In its investigations, MMA discussed the advantages and disadvantages of each option on the financial markets with financial market participants with views being expressed that option 1.1(b) may result in better financial instruments being developed and that this may increase liquidity in the market [ie Option 1.1(b) may provide a benefit]. Option 2.2 however, would frustrate financial contract trading due to the system volume weighted trading for market customers and therefore hinder market liquidity [ie option 2.2 may provide negative benefits – or at best, neutral outcomes]. MMA considered that these potential benefits were unquantifiable.

NEMMCO therefore makes its recommendations on the options to address 5/30 issue with the following information to hand, namely:

- A cost / benefit analysis clearly indicating that net gains to market efficiency would not be delivered by either option. [-$131.3M outcome for option 1.1(b) and -$27.0M outcome for option 2.2 respectively for the most likely medium scenario];

- Option 2.2 considered unacceptable by the working group and by NEMMCO; and,

- Some unquantifiable benefits may be delivered by the options in the area of financial markets. In particular, option 1.1(b) may result in better financial instruments being developed and that this may increase financial markets liquidity.

NEMMCO is not aware of any case to conclude that the last dot point above offsets the first to infer that net gains to market efficiency have been identified and demonstrated for either option.

15 Findings

Following two significant investigations into the 5 minute dispatch and 30 minute settlement issue, NEMMCO has reached the following findings:

- There are no options available to address the 5/30 issue in isolation which provide a demonstrable net positive benefit to the NEM with respect to market efficiency. Non-quantified and qualitative costs and benefits are not considered to be of sufficient magnitude or certainty to offset the excess of quantified costs over quantified benefits. As such, NEMMCO concludes that grounds to support the initiation of changes to the existing NEM arrangements have not been identified.

- The “No Change” option is therefore recommended.

NEMMCO considers that the market efficiency aspects of the 5/30 issue have now been investigated in detail, and subject to comments received in respect of this draft report, does not propose to further consider the matter in the foreseeable future.

16 Acknowledgments

NEMMCO is appreciative of the significant input from the working group members as representatives of their industry sectors throughout this investigation. That input has assisted in developing a clear understanding of the issues, potential options to address the issues, and cost estimates for respective industry sectors associated with the implementation of various options.

17 References

17.1 Background References

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NECA (National Electricity Code Administrator) 1999a, *Capacity Mechanisms in the national electricity market, An issues paper*, NECA, Adelaide, 29 January (URL http://www.neca.com.au/)

NECA 1999b, *Capacity mechanisms in the national electricity market,* Final Report, NECA, Adelaide, July

NECA 1999c, *Review of VoLL in the National Electricity Market*, NECA, Adelaide, 23 July

NEMMCO 1999d, *Anomalies in the NEM Due to Five-Minute Dispatch & Thirty-Minute Settlements*, NEMMCO, 3 September (URL http://www.nemmco.com.au/future/design/1182.htm)

NEMMCO 2001a, *Anomalies in the NEM Due to Five-Minute Dispatch & Thirty-Minute Settlements*, NEMMCO, 27 February (URL http://www.nemmco.com.au/future/design/1182.htm)

17.2 Documents resulting from this work stream on the 5/30 Issue

April 2001 Onwards:

Project Outline and Terms Of Reference

NEMMCO 2001b, *5/30 Minute Working Group - Project Outline and Terms Of Reference*, NEMMCO, March 2001. (URL http://www.nemmco.com.au/future/design/1182.htm)

Issue Definition Paper

5/30 Working Group 2001a, *5/30 Minute Issue Definition*, 5/30 Working Group, September 2001. (URL http://www.nemmco.com.au/future/design/1182.htm)

Options Paper

5/30 Working Group 2001b, *Options for resolving the 5 Minute Dispatch and 30 Minute Settlement Anomaly in the NEM*, 5/30 Working Group, September 2001. (URL http://www.nemmco.com.au/future/design/1182.htm)

MMA Issues Paper

McLennan Magasanik Associates 2002a, *Issues Paper: Modelling of the Efficiency Gains from Resolution of 5/30 Issue*, McLennan Magasanik Associates, 28 January 2002. (URL http://www.nemmco.com.au/future/design/1182.htm)

MMA Final Report

McLennan Magasanik Associates 2002b, *Benefits and Costs of Final Arrangements for Aligning Dispatch Prices and Settlements Payments*, McLennan Magasanik Associates, 28 January 2002. (URL http://www.nemmco.com.au/future/design/1182.htm)

Draft Efficiency Guidelines

NEMMCO 2002c, *Assessing the efficiency impact of proposed changes to the market arrangements – Draft Guideline*, NEMMCO, May 2002. (URL http://www.nemmco.com.au/future/design/108-0016.htm)

This Paper:

NEMMCO Draft Final Report: 5/30 Issue

NEMMCO 2001d, 5 Minute Dispatch and 30 Minute Settlement Issue – NEMMCO Draft Final Report, NEMMCO, May 2002. (URL http://www.nemmco.com.au/future/design/1182.htm)

18 List Of Attachments

APPENDIX A1:	5/30 Working Group Structure
APPENDIX A2:	Examples of the 5/30 Issue
APPENDIX A3:	Description of the Preferred Options
APPENDIX A4:	Costs Of Preferred Options
APPENDIX A5:	NEMMCO Draft Efficiency Guideline Comparison
APPENDIX A6:	Description of the 30 Minute Option

Appendix A1: 5/30 Working Group Structure

NEMMCO established the 5/30 Working Group in April 2001 to complete the review of the 5/30 issue in accordance with a project overview and Terms of Reference. Representation on the working group was requested by NEMMCO from industry groups such as the National Generators Forum (NGF) and the National Retailers Forum (NRF) as well as from parties considered likely to have an interest in the 5/30 issue.

NEMMCO was keen to ensure that effective representation occurred on the 5/30 Working Group for market sectors which were likely to be impacted in any way by resolution of the 5/30 issue. Meetings of the working group occurred both in person as well as by teleconference throughout the duration of this project.

The structure of the 5/30 Working Group is as follows:

Table 1 5/30 Working Group Structure

Industry Sector	**Representative Group: (Nominee/s)**
Generators	National Generators Forum : TXU, Southern Hydro
Retailer	National Retailers Forum: AGL, Country Energy
Retailer/Trader (hybrid)	Origin Energy
Trader	Enron Australia Finance Pty Ltd (removed following the suspension of ENRON from the NEM)
MNSP	TransEnergie
End Users	Energy Users Association of Australia: CSIRO as representative.
TNSP	National Electricity Market Operations Committee (NEMOC): VenCorp
NECA	NECA
NEMMCO	Convenor, Market and System Operator

Contact details for 5/30 working group members are located on the NEMMCO website[11].

[11] 5/30 Working Group Details: (URL http://www.nemmco.com.au/future/design/1182.htm)

Appendix A2: Examples of the 5/30 Issue

This appendix contains a number of specific examples that illustrate the impact of the 5/30 issue on NEM participants. The examples given are for a fast start generator, a typical large generator trip as well as an MNSP.

Example 1 – Fast Start Generator

Consider the example below in which the 5 minute pool prices are shown. The pool price is $20 in each five minute period except one that has a price of $1000. The half hourly averaging process results in a 30 minute price of $183.33.

The averaging process used to produce the 30 minute pool price dampens the true volatility of spot prices in the NEM which should reflect the cost to the market of the marginal generating plant – in this case plant bid at $1000 has been used to satisfy demand. The true price volatility is smeared across the half hour period.

5 Minute Interval	5	10	15	20	25	30	**Average**
Pool Price ($/MWh)	20	20	1000	20	20	20	**$183.33**

With the above dispatch prices, consider a 150MW fast start generator (hydro) that has a delay of 4 minutes and full loading after a further minute. The generator is only able to deliver 1/10th the desirable energy in the $1000 priced five minute period. In the settlement process the generator is paid at the average price even though it responded to the $1000 price signal.

Generation (MW)	0	0	150	0	0	0	**$183.33**
Energy (MWh)	0	0	1.25	0	0	0	**1.25**

A fast start generator in the example above would not get to produce energy to the market in the period containing the $1000 price, and as such would make some loss on a financial hedge contract. To take account of contract payouts due to the 5/30 issue, the generator would add on a premium component to all such contracts which directly increases the cost of hedging in the NEM. In reality of course, the generator would normally continue to run for a minimum “on time”. In this case the (high priced) generator would be generating in subsequent dispatch periods where the price is low !

Demand side participants are equally disadvantaged. A participant who calculates that they would shed load when prices reach say $200 would have shed load when the 5 minute price reached $1000. The half hourly settlement price of only $183 indicates that the ex-ante market pricing signal caused the participant to act inadvertently.

Example 2 – Generator Trip

Consider the example below in which a generator trips near the end of the fifth 5-minute dispatch interval. The pool price is $20 in each five minute period except the last one of the trading interval which has a price of $1000/MWh following the trip. The half hourly averaging process results in a 30 minute trading interval price of $183.33 – ie the average of the dispatch interval prices.

5 Minute Interval	5	10	15	20	25	30	**Average**
Pool Price ($/MWh)	20	20	20	20	20	1000	**$183.33**

↓ **Unit Trip**

Generation (MW)	500	500	500	500	500	0	**Total**
Energy (MWh)	42	42	42	42	42	0	**208**

In this case the generator has made a windfall profit as it produced no energy in the last high priced five minute period of the trading interval. Indeed the generator only produced energy at times when the dispatch interval prices were $20.00 / MWh and yet the existing NEM settlement arrangements result in the generator being paid at a price of $183.33 for ALL of the energy within the half hour period.

To highlight this issue, if the generator had a rating of 660MW and tripped from full load, the results would be as follows:

Generation in the 5 dispatch intervals	= (660/12)*5	=	275MWh
Settlement payments with 5/30 issue	= 275 * $20.00 /MWh	=	$5,500
Settlement payments with 5/30 issue Removed	= 275 * $183.33 /MWh	=	$5,500

Windfall Profit (from tripping) = $ 44,916

Example 3 – MNSP

Consider the example below in which a MNSP is dispatched. The pool price is more volatile in region B within the trading interval. The half hourly averaging process results in 30 minute regional prices of $47.84 and $155.42. The MW flows on the interconnector are shown below:

Prices:

5 Minute Dispatch Interval	**5**	**10**	**15**	**20**	**25**	**30**	**Average**
Pool Price Region A ($/MWh)	$48.74	$49.06	$49.07	$48.79	$48.52	$42.87	$47.84
Pool Price Region B ($/MWh)	$652.54	$105.44	$50.33	$50.31	$38.95	$34.95	$155.42

MW Flows on the interconnector

5 Minute Interval	**5**	**10**	**15**	**20**	**25**	**30**	**Average**
Dispatch (MW)	56	56	0	0	-52	-52	8

In this case the MNSP has had both directional flows across the interconnector within the one trading interval. The revenue outcome for 5 minute settlement would be $2,709.97 compared to $341.38 for 30 minute settlement.

Example 4 – Other MNSP examples

Similar examples can be shown for MNSPs that result in the following:

- reversing power flows across the 30 minute trading interval having a net zero power flow in the trading interval. In this case, the MNSP owner derives zero income even though its commercial assets have been utilised and operated in accordance with market dispatch price signals;

- reversing power flows across the 30 minute trading interval having a positive average power flow in the trading interval from region A to region B and the trading interval price for region A is higher than that for region B.

  In this case, the MNSP owner derives negative income (ie pays out) even though its commercial assets have been utilised and operated in accordance with market dispatch price signals.

Appendix A3: Description of Preferred Options

Option 1.1 (b) 5 Minute Dispatch And Simulated 5 Minute Settlement

"Simulated 5 minute dispatch and settlements achieved by profiling existing 30 minute energy data".

Summary

This option achieves the benefits of 5 minute settlements without going to the expense and implementation delays of modifying meters and massive IT systems modifications for participants as well as for NEMMCO. The option is conceptually very simple and may be thought of as an extra ex-post settlements module operating to redistribute adjustment payments to counter the 5/30 issue. Under this option, no changes are made to published dispatch and pricing market outcomes.

Option 1.1(b) introduces a "Simulated 5 minute Settlement" regime which is compulsory for all Market Generators, MNSPs and interconnectors and optional for Market Customers. Under this arrangement, SCADA data is used to profile 30 minute interval metering data (using existing meters) into 5 minute profiled volume data. Simulated 5 minute settlements can then be performed for these participants by using the five minute dispatch prices and the 5 minute volume data.

Individual market participants that participate in the Simulated 5 Minute Settlement arrangement also have the option to install 5 minute interval metering (revenue quality 5 minute interval metering) at their own expense to replace the SCADA data profiling methodology or where SCADA data is not available for a Market Customer. It would be expected that the number of such participants interested in exercising this choice would be relatively small and restricted to those that can rapidly respond to price signals and therefore justify the expense of the additional metering overheads.

Market Customers who choose NOT to participate in the Simulated 5 Minute Settlement arrangement are settled under the existing arrangements using their individual 30 minute interval meter energies and the time weighted average 30 minute Trading Interval price.

Option 1.1(b) results in a settlements imbalance from the differences in aggregated settlement payments between the two settlement methods employed. This settlement imbalance is recovered from the remaining market customers NOT opting to be involved in the Simulated 5 Minute Settlement regime. The allocation of the total settlement imbalance for a 30 minute trading interval across all market customers not involved in the Simulated 5 Minute Settlement regime would be performed regionally on a pro-rated by energy basis.

The cost recovery mechanism for the settlement imbalance from Option 1.1(b) would be in the form of a market levy (settlement fee) or an additional ancillary service. The detailed structure of the imbalance recovery mechanism would be an issue for implementation if warranted.

Regional spot prices for energy published by NEMMCO would be unchanged from existing market arrangements:

- 5 Minute Dispatch prices; and,
- 30 minute time weighted average prices.

The key features of Option 1.1(b) are summarised in the table below.

Key Features of Option 1.1(b)

Option 1.1(b) **Option Description**	**5 minute Dispatch and Simulated 5 Minute Settlement**
Option Features	
Key Time Periods For Energy	(unchanged from current NEM arrangements)
Dispatch period for energy	5 Minutes
Spot Market Settlement period	30 Minutes
Financial Markets Contracting Period	30 Minutes
Metering Arrangements	Energy Market
Meters	All Participants: No change from existing NEM 30 minute interval meters. Simulated 5 minute settlement energy data produced for Market Generators, MNSPs and optionally for Market Customers by profiling the 30 minute interval meter data with aggregated 5 minute SCADA data.
Optional 5 minute meters	Participants partaking in the simulated settlement regime and market customers may opt (at their own cost) to install 5 minute interval metering if they consider that they require a greater level of profiling data accuracy or reliability than that afforded by SCADA data.

Settlement Calculations	**Energy Market Settlements** Generators, MNSPs and Market Customers who opt for 5 minute interval metering: Complete 5 minute settlement. This means that volume generated or consumed in a 5 minute interval (as read by 5 minute interval meters) are settled using the 5 minute ex-ante dispatch price applicable to that 5 minute interval. Other Generators and MNSPs (default 30 minute interval metering): Default settlement arrangement is simulated 5 minute settlement. This means that SCADA data is used to profile existing 30 minute metered energy data into a 5 minute profile for a trading interval. A simple settlement adjustment factor is then calculated for each meter. The profiled five minute volumes generated or consumed at a meter are then effectively settled through this methodology using the 5 minute ex-ante dispatch price applicable to each 5 minute interval. This achieves simulated 5 minute dispatch and settlements with settlement outcomes for these participants being the same as for full 5 minute settlement. Remaining Market Customers (default 30 minute interval metering): These customers do not participate in simulated 5 minute settlements. The settlement regime remains unchanged with settlement occurring using 30 minute time weighted average pricing and 30 minute interval metering data. The settlement imbalance that is created by this option is recovered entirely from these participants (pro-rated by energy) with a settlements levy or new ancillary service.
Ancillary Services	Existing market FCAS services and their cost recovery mechanisms are unchanged by this option. An additional ancillary service may be established under this option for customers not participating in simulated 5 minute settlements to account for the settlements imbalance created by the different settlement methods. In this way the settlements imbalance would be passed through to end users as an ancillary service.
Energy Market Prices	Prices published for the energy market will be unchanged from existing market arrangements. NEMMCO will publish the following prices for each trading interval: 5 Minute Dispatch prices

	30 minute time weighted average price

Implementation Issues – Option 1.1(b)

Implementation Issues that have been identified by the working group for each option fall into the areas shown below.:

- Settlements Issues;
- Use of SCADA data;
- Treatment of Loss Factors for some Market Customers;
- Secondary financial market hedging;
- MNSP specific metering issues;

The following tables briefly describe the implementation issues. These issued would need to be fully addressed should this option prove to be recommended for implementation.

Design Area	**Brief Description**
Settlements Imbalance	A cost Recovery mechanism required to address the settlements Imbalance introduced by the IES methodology.
Use Of SCADA Data	Compliance with the National Measurement Act 1960. Verification is required that SCADA data is acceptable as a means of measurement or for pro-rating revenue quality meter data.
SCADA data reliability	What procedures are to apply in the event of a “routine SCADA data failure” (both localised failure and regional failure). Acceptable procedures would be required to be established by the market.
Secondary Market Hedging	Little ability to hedge a imbalance recovery mechanism.
Settlements - MNSP	MNSPs would require bi-directional metering.
Treatment of Loss Factors	Loss Factors for some Market Customers need to be managed to account for different tiered metering structures where applicable.

Cost Recovery Mechanism

The IES proposal detailed in the 5/30 working group “Option Paper” involves a simulated 5 minute dispatch and settlement, with a mandatory involvement of market generators and an optional involvement of market customers. The existing dispatch and pricing arrangements are unchanged, however, a new adjustment process occurs during the settlement process.

A regional settlement imbalance arises due to a settlement adjustment being implemented by this option. In essence, the difference between the 5 minute simulated settlement outcome (for market generators, MNSPs and for those market customers choosing to participate) and the existing settlement arrangement is determined and this amount is then recovered from the remaining market customers not participating in this regime.

The settlements imbalance is determined on a regional basis and is initially a gross imbalance amount ($). This amount can be included as a 30 minute settlement adjustment to those retailers/customers not participating in the 5 minute simulated settlements process. The settlement adjustment would be performed on a pro-rated basis by energy consumption in the 30 minute trading interval.

Options for the recovery mechanism

The settlements adjustment could be defined as either a settlements uplift (ie a direct charge) or alternatively as an ancillary service. The selection of the method used to address the settlements imbalance is an implementation issue. The choice between recovery mechanisms would not significantly change the bulk of the costs estimates – ie retailer cost estimates (this was verified with the retailer representatives of the working group).

Option 2.2 Hybrid Demand Weighted Option

Option 2.2 provides the alternative approach to addressing the 5/30 Issue. Rather than trying to align the dispatch and settlement intervals across the entire market, this option uses a volume weighted methodology.

Key features of this methodology are:

- Compulsory (new) 5 minute interval metering for generators, interconnectors and MNSPs with existing 30 minute interval metering for all market customers.

  This enables the supply side of the market to have a full 5 minute dispatch and settlement regime. Individual generators are then effectively paid a 30 minute volume weighted average (VWA) price weighted against their own 5 minute metered generation. Individual generators therefore receive their own volume weighted price This is equivalent to 5 minute settlement for individual generators.

- All Market Customers pay the same 30 minute System Volume Weighted Average price weighted against the system demand. This system volume weighted average price would become the new published trading interval price (ie replace the time weighted average price 30 minute price) and is calculated as follows:

$$\mathrm{SystemVWAPrice} \equiv \frac{\sum_{AllDispatch\_interval} \mathrm{TotalSystemDemand} * 5\mathit{MinuteDispatchPrice}}{\sum_{AllDispatch\_interval} \mathrm{TotalSystemDemand}}$$

- In order to maintain a balanced settlement outcome the volumes transacted on both the supply and demand sides of the NEM must also balance. To achieve this balance, the volumes used in the payments to generators from their 5 minute interval metering must be the same in aggregate as those used in the calculation of the system volume weighted price for each trading interval.

  5 Minute interval meter data for generators would be polled once per week. A consequence of this feature is that **estimates for the system volume weighted price must be made in real time** for the publication of trading interval prices, with these estimates being replaced with revised system volume weighted prices for all trading intervals during the previous week. SCADA data would be used to produce price estimates. That is to say that this option produces estimate trading interval prices with all trading interval prices being revised at the end of the week.

  Note that the supply and demand sides of the market effectively see different prices.

Advantages of Option 2.2

- Provides clear pricing signals to generators consistent with a competitive market.
- Directly resolves the materiality of the 5/30 issue for generators by providing the same financial outcome as 5 minute settlements.
- Low impact in terms of implementation issues such as cost, transition issues and complexity.

Disadvantages of Option 2.2

- Does not clarify the boundary between energy and Ancillary Services from the existing NEM structure.
- Does not resolve the 5/30 issue for customers.
- Does not provide clearer investment signals for individual customer's demand side participation. When an individual market customer sees a market high 5 minute price and curtails load as a direct response to that 5 minute price signal, the resultant benefits are effectively smeared over all market customers in the region.
- Tensions created in the secondary financial markets as generators and market customers no longer see that same common clearing price for all payments. This may materially impact liquidity for financial hedge contracts.

Implementation Issues – Option 2.2

Implementation Issues that have been identified by the working group for each option fall into the following area:

- Secondary financial market hedging
- SCADA data used for estimates
- Settlement Issues

Further details of the implementation issues are contained in the following table.

Design Area	Brief Description
Financial Markets	Changing the basis upon which the 30 minute trading interval price is calculated has impacts in the financial markets. This price affects the underlying commodity reference price source and may/would therefore require some (all) financial market electricity contracts to be re-negotiated. This would necessarily incur costs for NEM participants.
Use of SCADA data for VWA price estimates	Defined procedures will be required in the event of a "routine SCADA data failure. (both localised failure and regional failure). Confidence and stability in market processes and contract settlements would be undermined by unreliable price data - firmness of real time pricing is essential to the development of the market
Settlements	There may be a settlements imbalance issue if a market generator is embedded below the Transmission measured connection point.
Settlements	There will be an imbalance introduced because of transmission losses. This assumes that the volumes being used are the adjusted gross energies at transmission connection points. The problem could be partially alleviated by using the effective gross energies at the Regional Reference Nodes, but this does not completely eliminate the imbalance because the fixed TLFs are set for average conditions. They are not optimised for times of high system stress when high prices are likely.
Settlements	In the Snowy region, there will be special difficulties with the VWA price because the regional generated volume could be vanishingly small. It could be negative if there are only T3 pumps in service for example.
Use of SCADA data for VWA price estimates	What procedures are to apply in the event of a "routine SCADA data failure. (both localised failure and regional failure) Confidence and stability in market processes and contract settlements would be undermined by unreliable price data - firmness of real time pricing is essential to the development of the market

Appendix A4: Costs Of Preferred Options

This appendix includes additional information relating to the costs of the preferred options. This includes:

- The process for collating costs;
- Responsibilities for estimating costs;
- Special retailer issues;
- Costs not quantified; and,
- Summary of the costs.

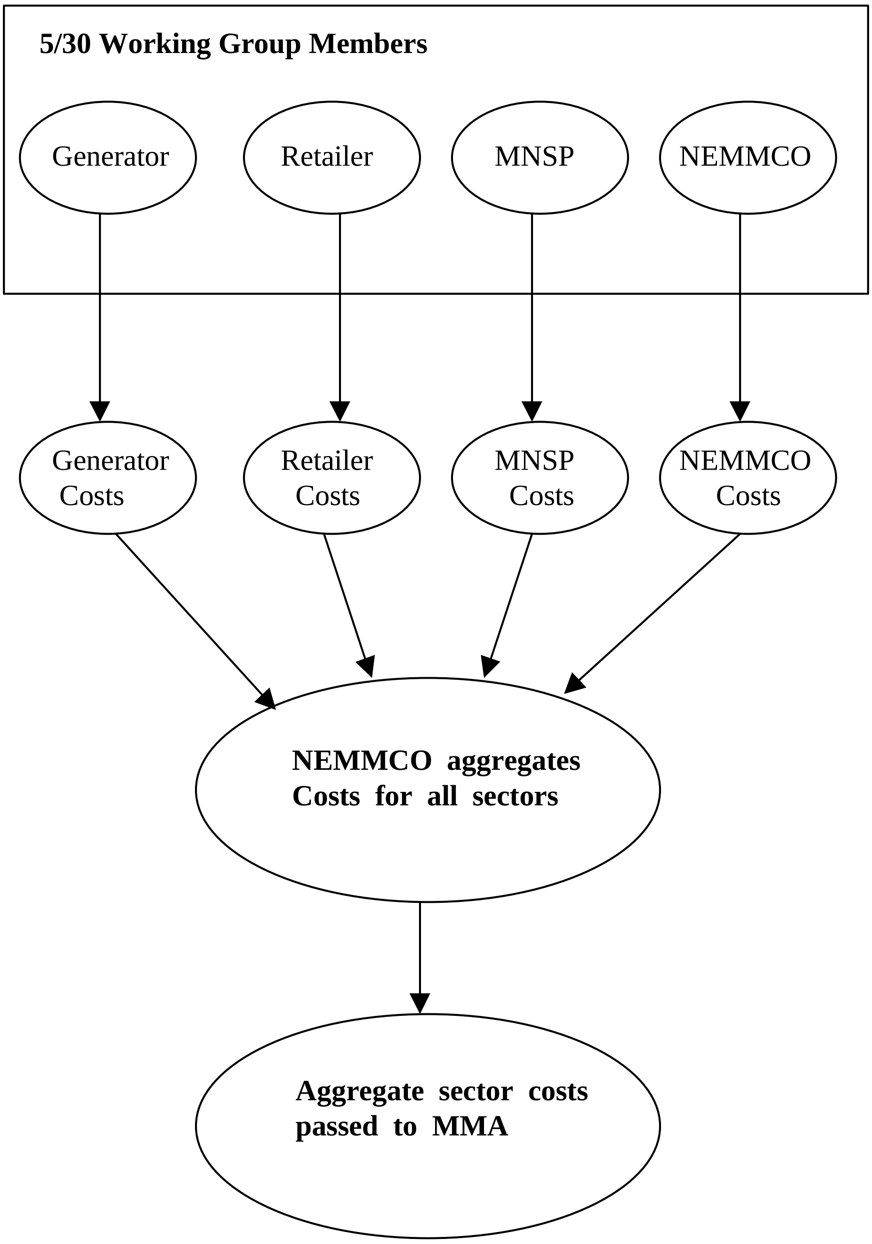
1. **The process for collating costs**

A working group process was used to investigate the 5/30 issue as described in section 4. NEMMCO convened the working group and sought membership nominations across all NEM industry sectors. Where possible, representatives were sought from industry bodies such as the National Generator Forum (NGF) and National Retailer Forum (NRF) rather than from specific companies within a sector so that information regarding the project would be effectively disseminated and that information received back into the working group had been discussed within NEM sectors forums or groups and consensus views were therefore presented back to the working group whenever relevant or possible.

Once potential options to address the 5/30 issue had been identified and then distilled into two preferred options for detailed analysis, NEMMCO requested that costs associated with both options be estimated by the working group members for their respective industry sector in aggregate. Cost estimates for both upfront costs and annual ongoing costs were sought. The NGF nominees, for example, estimated the costs for NEM generators, NRF nominees estimated the costs for retailers and so on.

Aggregate cost estimates were forwarded to NEMMCO who then forwarded the cost data to MMA for incorporation with their benefit modelling work to produce Net Benefit results for each option. The following diagram shows the flow of cost information from the working group members to MMA (via NEMMCO).

Obtaining and processing aggregate sector cost data:



2. **Responsibilities for estimating costs**

The working group representatives gathered and reported cost estimates for their respective industry sectors. These include generators, retailers, MNSPs, NEMMCO (system operator costs).

MNSP IT system cost estimates were assumed to be similar to those of a generator

3. Special retailer issues

Cost estimates for the retail sector were the most time consuming to obtain due to the need for a full cost estimate survey. The retailer representatives on the working group expressed concerns that the costs may vary from one retailer to the next due to differences in IT systems sophistication as well as whether or not the retailer incorporated a network business.

To address these concerns, itemised cost estimates for a typical retailer business were prepared by the retailer working group members and these were circulated to all retailers via the National Retailer Forum (NRF) in the form of a cost estimate survey. Individual retailers expressed concerns that disclosing the individual cost estimates in the survey could in some way release commercial information to the retailer working group members. NEMMCO agreed to act as the recipient of the individual survey responses (in confidence) and to then aggregate the retailer costs before forwarding the aggregate cost estimates to MMA (together with the other sector costs) for inclusion in the Net Benefit calculation. In this way, commercially sensitive cost information would be jeopardised.

NEMMCO does not believe it is in a position to challenge the costing data as supplied by the working group representatives for their respective industry sectors.

NEMMCO did however, pay close attention in understanding the costing estimates from retailer sector because these costs made up more than 95% of costs for option 1.1(b) and 46% of costs for option 2.2. The retail sector also faced more than 90% of the ongoing costs for the options. NEMMCO's observations of retailer cost data included requests for more detailed descriptions of itemised retailer cost elements and in some cases re-verification of individual cost items. This process resulted in a number of revised retailer cost estimates prior to final submission of the aggregate costs data to MMA.

4. **Costs not quantified**

The final aggregate cost estimates used in the cost benefit analysis do not include some smaller costs that are applicable to the options. These costs were not pursued in detail as they appeared as an order of magnitude less than costs on other areas of the market and were therefore a secondary consideration.

Had the final results appeared closer – or swayed just in favour of benefits, then these costs would have been further investigated and added to the final analysis.

These costs include metering modifications on interconnectors, MDA communications costs for interconnectors, MNSP metering costs (bi-directional 5 minute metering) as well as some minor NEMMCO systems costs.

5. Summary of the costs

The following table shows a summary of the aggregate NEM upfront and annual costs identified by industry representatives for each option. These costs are shown brought forward to a net present value in mid 2002 dollars.

Implementation and ongoing costs, $M, mid 2002 dollar terms

	NPV	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Option 1.1(b)	160.2	74.4	13.8	13.8	13.8	13.8	13.8	13.8	13.8	13.8	13.8	13.8
Option 2.2	54.5	32.3	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7

Clearly, both options result in significant costs to the NEM, with option 1.1(b) having significantly greater costs due to both higher up front costs and significantly higher ongoing costs. The following table provides a break-up of the costs by stakeholders.

Table 4.4 Totals summary of all costs by stakeholder ($M)

	Upfront Costs		Ongoing Annual Costs	
Sector	**Option 1.1 (b)**	**Option 2.2**	**Option 1.1 (b)**	**Option 2.2**
Retailers	71.3	13.8	13.6	$ 3
Generators	2.0	16.7	0.2	$ 0
NEMMCO	1.0	1.0	-	-
MNSP	0.1	0.8	0.0	$ 0
Other	-	-	-	-
Total	74.4	32.3	13.8	3.7

The majority of costs are incurred in the retailer sector of the NEM for both upfront costs as well as ongoing annual costs. The majority of these retailer costs are attributed to necessary IT systems enhancements for either option.

Retailer Costs

Significantly more work was performed to obtain costing estimates for retailers to manage the options to address the 5/30 issue. The costs were supplied to NEMMCO from the NRF representatives on the 5/30 working group in two stages.

Firstly, an estimate of the costs was performed by Country Energy, including in-house workshopped sessions to initially identify affected cost item areas. Cost estimates for these items were then made to represent a "typical retailer". A second cost estimate process was performed at a later stage during the project where the working group representatives compiled the first stage work into a cost survey which was sent to all Retailers via the NGF.

Indicative costs for each cost item area were supplied from the retailer working group members (AGL and Country Energy) and all retailers were asked to complete their own cost estimates indicating in particular where their business costs varied from the typical retailer estimate costs.

Retailer Cost Survey

The retailer cost survey posed the following key question:

"What incremental (net) costs would be incurred by your business as a result of implementing and operating the new arrangements?"

Incremental costs should be assessed by comparison to the costs that would be incurred in continuing with business under a no change scenario – see the follow simple example:

Example Methodology to calculate "Net Costs":

	Gross expenditures			**Net costs**	
	No change	**1st option**	**2nd option**	**1st option**	**2nd option**
Cost Item 1					
Once-off	zero	C	G	C	G
Recurring	A	D	H	D – A	H – A
Cost Item 2					
Once-off	zero	E	J	E	J
Recurring	B	F	K	F – B	K – B
Totals				ΣOnce-offs ΣRecurring	ΣOnce-offs ΣRecurring

The cost survey is interested in is the "ΣOnce-offs" and "ΣRecurring" costs. **Gross expenditure estimates are confidential information (and will remain) known only to the individual business.** In order to protect this confidentiality, the results of the cost survey were returned to NEMMCO rather than directly to the retailer representatives on the working group. The aggregate costs were then given to the retailer representatives on the working group – as well as to MMA for inclusion in the "Net Benefit" calculation.

The following generic cost item template was used for the survey. Individual retailer businesses may or may not have identifiable costs for any one cost item due to differences in either business structure and IT systems.

Generic Retailer Cost Survey Template:

Items	Impact on Business Unit	Responsibility Area	Brief Description
1	Billing	Network Bus.	Network bill calculation
2	Billing	Network Bus.	Data Structure & Management
3	FRC	Retailer	Forecasting and exposure upgrade
4	Billing	Retailer	Bill Calculation engine
5	Billing	Retailer	Data structure
6	Billing	Retailer	NMI Configuration
7	FRC	Retailer	MSATS Profile management
8	Data Services	Retailer	Aggregation integration to Billing
9	Data Services	Retailer	Aggregation integration to S&M
10	Data Services	Retailer	Data Acquisition and validation
11	Energy Trading	Retailer	Contract evaluation and reporting
12	Energy Trading	Retailer	Sensitivity Analytics & Forecasting
13	Sales & Marketing	Retailer	Quote Calculation engine
14	Sales & Marketing	Retailer	Data structure
15	Sales & Marketing	Retailer	NMI Configuration
16	Settlements	Retailer	Energy cost calculation (CFD)
17	Settlements	Retailer	Pool Bill Reconciliation
18	TLF/DLF	Transmission	Revise TLF calculation model
19	Metering	Transmission	Meter Upgrade & Reprogramming Provision
20	Metering	Retailer	Meter Provider Costs
21	Billing	Retailer	Training
22	Metering	Retailer	MDA associated costs
23	Others		

As discussed in the cost area in the main document, NEMMCO does not believe it is in a position to challenge the costing data as supplied by the working group representatives for their respective industry sectors. NEMMCO did however, pay close attention in understanding the above costing estimates from retailer sector because these costs made up more than 95% of costs for option 1.1(b) and 46% of costs for option 2.2. The retail sector also faced more than 90% of the ongoing costs for the options.

During the aggregation process, NEMMCO's observations of the retailer cost data resulted in discussions with the retailer representatives on the working group and requests for more detailed descriptions of itemised retailer cost elements. In some cases re-verification of individual cost items was required. This process resulted in a number of revised retailer cost estimates prior to final submission of the aggregate costs data to MMA.

Cost estimates supplied to MMA grouped retailers into 2 categories and therefore two cost estimates with one type having a combined retail and network business, and the other having just a retail business.

Generator and MNSP Costs

Generators also incur costs in the areas of data, IT systems, metering and re-negotiating financial contracts required to manage the changes in the alternative options compared to the no change scenario. These costs were estimated by the generator representatives on the 5/30 working group for both upfront costs and annual ongoing costs.

Typical Generator Costs items:

Cost Item	Description
1.	5 minute revenue metering for generators
2.	Extra data storage
3.	Local SCADA feed
4.	Verification calculations
5.	Settlement System Changes
6.	Re-negotiation of contract prices

MNSPs (currently only TransEnergie) were assumed to have costs of the same order as a small generator business.

NEMMCO

Estimates of NEMMCO costs were made to account for modifications required to IT systems in the area of post dispatch processing, settlements and interfaces. Costs estimates for NEMMCO were small compared to generators and retailers, not materially different for either option and of the order of $1M in upfront costs and a small (but not quantified) ongoing annual maintenance cost.

Appendix A6: NEMMCO Draft Efficiency Guideline Comparison

This appendix presents the results of an application of the NEMMCO Draft Efficiency Guidelines[12] to the 5/30 project.

The results shown in this appendix should be read in conjunction with the NEMMCO Draft Efficiency Guidelines and in particular, readers should familiarise themselves with the pertinent questions raised in the 'Aide memoire' section of the guidelines in regard to assessing changes to the NEM.

[12] Draft efficiency guidelines have been developed by NEMMCO and are open for consultation until 31/5/2001. These draft guidelines, when finalised, are intended to be used to assess changes to the NEM in terms of improving market efficiency. As the guidelines were developed during the analysis phase of the 5/30 project (towards the end of 2001), the comparison presented in this appendix will provide a timely opportunity to test the draft guidelines on a real project as well as confirming that the analysis undertaken during the 5/30 project has considered issues contained in the guidelines.

Assessing the efficiency impact of resolving the 5/30 issue

Two options have been proposed to address the 5/30 issue in the NEM. Descriptions of both options are contained in Appendix A3 of this document as well as the 5/30 Working Group's "Options Paper".

NEMMCO's draft efficiency guideline details a 4 stage process in assessing changes to market arrangements. This 4 stage process is addressed in this appendix.

The proposal(s)

1. Description of the proposal(s) under consideration

Evaluation of options to address the 5 minute dispatch and 30 minute settlement anomaly in the NEM.

Stage 1 – Reasons for the prospective change to market arrangements

1. Description of the limitations or problems in the present arrangements that the proposal is aimed at addressing

Dispatch in the National Electricity Market (NEM) is done every 5 minutes. However, settlement of payments is carried out on a 30-minute interval, with generators and market customers receiving payments based on the average price for the six dispatch intervals in each settlement period. Many participants in the market have raised concerns over the efficiency of this arrangement, claiming that they discouraged dispatch of fast ramping plant in the market and therefore lead to higher costs.

This occurs, for example, when a high cost, fast start generator is dispatched to respond to a 5 minute high price spike, yet only receives payment on a lower half hourly average price. Alternatively a fast response load may not respond to short term price signals due to the reduced incentive of a lower 30 minute price.

This project aims to assess the merits of resolving the 5/30 issue.

2. Rationale for the present market arrangements

The current dispatch and settlement arrangements are the market design as implemented at the start of the NEM. The 5 Minute dispatch interval is a carry over from typical power system controls timeframes at that time. The 30 minute trading interval was a function of both the limit of computer processing capability and general market opinion at the time as to a suitable trading interval.

3. Details of any previous proposals to address the identified limitations or problems in the present arrangements, together with reasons for their success or failure

See the background section of this document.

4. Assessment of the practicality of the prospective change, focussing in particular on whether it can be implemented without significant alteration to existing arrangements

Both options under consideration (In addition to the no change reference scenario) are considered to be realistic in terms of their ability to be implemented. The 5/30 Working Group considered this analysis aspect when forming potential options to address the issue. A number of pros and cons were identified for each option involving implementation issues. These features are summarised in the "Options Paper" published by the 5/30 working group: (URL: http://www.nemmco.com.au/future/design/1182.htm)

Option 1.1(b) requires minimal changes to the existing market arrangements as it is implemented as an additional process in the settlement of the NEM. All other market features including dispatch, predispatch, trading interval prices as well as the external financial contracting market remain unchanged.

Option 2.2, however, does involve significant NEM changes from published market priced from a time weighted average to a modified volume weighted average. This introduces a level of complication to the market in terms of price symmetry. Generators receive a volume weighted average price for the volumes – weighted against their own 5 minute metered volumes. Customers, however see the trading interval price which is a volume weighted price weighted against the system demand.

5. Assessment of whether the proposal raises any policy matters that should be raised with relevant policy-makers

This project identified financial transfers between market participants that would occur in any proposal to address the 5/30 Issue. These transfer payments are not efficiency benefits and are discussed in the conclusions of this document as well as in MMA's Final Report.

• **Are there any cross-subsidies embedded in existing market arrangements relating to the issue being addressed?**	*No*
• **What transfers arise between market participant through implementation of the proposal**	*Transfers will arise under both options to address the issue. Generally, these transfers will be from the demand side of the market to the supply side of the market. Transfers are discussed further in the conclusions and recommendations of this report.*
• **Are there any externalities that may arise?**	*The MMA analysis of the market benefits that arise from each option are subject to a number of externalities such as market outcomes, demand growth, weather etc. These modelling assumptions are discussed further in the MMA final report.*
• **Are new markets being created or existing markets eliminated?**	*Both options subjected to detailed analysis may create new competitive sub-markets for short term price responsive generation.*
• **Is there any potential impact on the level of market power that can be exercised by a (group of) participant(s)?**	*Yes. Market power is discussed in the MMA final report.*
• **Are there any other matters that could be considered to have policy implications?**	*No.*

Stage 2 – Consistency of the prospective change to market arrangements with principles and objectives in the Code

1. Statement of how the prospective change to market arrangements would contribute to meeting the Code requirements regarding:

• **1.3(b): Market objectives**	*Resolving the 5/30 Issue will remove the existing pricing inefficiency and sub-optimal utilisation of price responsive plant in the NEM. In addition, the incentives for price responsive plant to bid into the market in an inefficient manner in the dispatch timeframe to protect contract exposures over the trading interval will be removed. The clarified price signals may result in changed efficiency in terms of plant investment.* *This project will therefore have a positive impact on meeting the Market Objectives in terms of competition between price responsive plant [Code clause 1.3(b)(1)] as well as removing what could be perceived as a technology bias in the NEM [Code clause 1.3(b)(4)]. It is NEMMCO's view that this is not a technology bias as all participants interact with the NEM under the same rules, but rather an aspect of the settlement process which benefits slower responding generators more so than fast response plant only in so far as fast response plant may not be able to extract value from their assets to their full capability.*
• **1.4: Code objectives**	*This project does not have an impact on the Code objectives.*
• **3.1.2: Purpose of the market rules**	*The proposal will result in changes to market efficiency in the NEM through restoration of appropriate market price signals. This reflects positively in terms of the market rules:* *"to create a regulatory environment which promotes an efficient, competitive and* reliable market *for the wholesale sale and purchase of electricity."*
• **3.1.4: Market design principles**	*This project does not have an impact on the Market Design Principles.*
• **Other relevant Code provisions**	*Nil*

2. Areas where adopting the market change could have a detrimental effect on the delivery of the above objectives	
Nil	
3. On balance, will the prospective market change be likely to lead to better delivery of:	
• **market objectives**	*On balance, the proposals to address the 5/30 issue would have a slight positive impact on the market objective 1.3(b)(1) - "the market should be competitive". This is due to the creation of an effective sub-market on the provision of short term price responsive generation.*
• **code objectives**	*Resolution of the 5/30 issue may result in marginally increased competition among short term price responsive plant.*
• **market design principles**	*No Impact*

Stage 3 – Assessment of benefits and costs

1. What assumptions have been made regarding this proposal to change market arrangements

Assumptions applicable to both the options themselves as well as the modelling and NEM physical and regulatory environment are detailed in the following:

- 5/30 working group "Options Paper"
- The MMA final report appendices

The interpretation of code clauses in regard to efficiency are detailed in the efficiency section of this paper as well as the MMA final report

2. Impact on customers and end-users of electricity [refer to questions contained in the 'Aide memoire' appendix of *Assessing the efficiency impact of proposed changes to market arrangements – Draft guideline*] – indicate the extent to which benefits and costs are quantifiable:

• **Brief description of how the proposal will affect customers (advantages and disadvantages)**	*Both options to address the 5/30 Issue will result in financial transfers between market participants that will most probably see market customers pay more. This will be chiefly related to transfer payments from the demand side of the market to the supply side (mainly peaking generators and hydro plant). Proponents of the options argue that this will to some extent be offset by benefits in the financial contracts market. Option 1.1b will give market customers greater access to benefits from demand side participation whilst option 2.2 will provide no greater incentive than the existing NEM arrangements.*
• **Once-off benefits**	*N/A*
• **On-going benefits**	*Increased transparency of market processes.*
• **Once-off costs**	*IT systems to manage the new arrangements (both options), metering overheads for some market customers (new metering and disposal costs for redundant metering for option 1.1b) and contract re-negotiation costs (option 2.2 only). Costs have been quantified in MMA's final report and Appendix A4 of this report.*
• **On-going costs**	*Maintenance of IT systems. Costs have been quantified in MMA's final report and Appendix A4 of this report.*

3. **Impact on retailers [refer to questions contained in the 'Aide memoire' appendix of *Assessing the efficiency impact of proposed changes to market arrangements – Draft guideline*] – indicate the extent to which benefits and costs are quantifiable:**

• **Brief description of how the proposal will affect retailers**	Retailers are not significantly affected by this issue. The proposed options will however, affect existing financial contracts under option 2.2 together with changes to market volatility and less market transparency. Hedges may be more readily available and with possibly less conservatism priced into the associated premiums for upper end price protection type products.
• **How might retailers be advantaged or disadvantaged?**	Disadvantaged by higher average prices arising from the removal of the averaging process of dispatch prices in settlements which suppresses volatility in the market.. Advantaged by more flexibility in the financial hedging markets arising from price responsive plant greater volumes and willingness to enter financial hedge products. Option 1.1(b) will also provide the optionality to participate in the simulated 5 minute settlement regime
• **Once-off benefits**	*N/A*
• **On-going benefits**	*Increased transparency of market processes.*
• **Once-off costs**	*IT systems to manage the new arrangements (both options), and contract re-negotiation costs (option 2.2 only). Costs have been quantified.*
• **On-going costs**	*Maintenance of IT systems. Costs have been quantified in MMA's final report and Appendix A4 of this report.*

4. **Impact on NSPs [refer to questions contained in the 'Aide memoire' appendix of *Assessing the efficiency impact of proposed changes to market arrangements – Draft guideline*] – indicate the extent to which benefits and costs are quantifiable:**

• **Brief description of how the proposal will affect NSPs**	*Little or no impact on TNSPs. MNSP's will be affected by the changes to dispatch and settlement arrangements which will result in more consistent market payments for behaviours consistent with dispatch prices.*
• **How might NSPs be advantaged or disadvantaged?**	*Bi-directional metering and payments equivalent to those for full 5 minute dispatch and 5 minute settlements will address MNSP concerns about the 5/30 Issue and the correlation between dispatch and 5 minute price signals.*
• **Once-off benefits**	*N/A*
• **On-going benefits**	*Benefits will appear as transfer payments towards MNSPs. Market payments would be consistent with dispatch therefore allowing MNSPs to be able to more effectively operate in the market.*
• **Once-off costs**	*Upgrading metering costs and IT systems costs will occur under both options. Costs have been quantified.*

• **On-going costs**	*Maintenance of IT systems. Costs have been quantified.*

5. Impact on generators [refer to questions contained in the 'Aide memoire' appendix of *Assessing the efficiency impact of proposed changes to market arrangements – Draft guideline*] – indicate the extent to which benefits and costs are quantifiable:

• **Brief description of how the proposal will affect generators**	*Base load generators will be generally ambivalent to the changes. Price responsive generators (peaking and hydro plant) will benefit from the options to address the 5/30 issue as the disparity between pricing and dispatch is removed (Payments will reflect dispatch conditions). Incentives for bidding behaviour inconsistent with price signals will be removed (such as fast start generators trying to maximise dispatched volumes in periods after a price spike in an attempt to minimise payouts on 30 minute financial contracts).*
• **How might generators be advantaged or disadvantaged?**	*Price responsive generators would be advantaged by the new arrangements for both options. Resultant market payments to these participants would be equivalent to those under a full 5 minute dispatch and 5 minute pricing regime.*
• **Once-off benefits**	*Some existing metering equipment may not be capable of being reprogrammed to adapt to the arrangements under the proposed options. Whilst the meter types have not been specifically identified in this project, the disposal value will offset the costs of the replacement equipment.*
• **On-going benefits**	*Credit assessment of some peaking generators may be enhanced.* *Both options will enhance the predicability of dispatch patterns.* *Options may introduce a new market segment into the NEM where price responsive plant have a greater level of competition.* *Benefits would certainly occur for both options in the form of transfer payments (although these are not efficiency benefits)* *Options will allow peaking generators the ability to better manage the risks associated with selling upper end financial hedge contracts. The propensity for these generators to offer cap type products to the market would also be improved.*
• **Once-off costs**	*New metering costs may be involved where metering is required by an option to be upgraded, although these additional costs will be offset by the disposal value of the metering it is replacing. IT systems, data and contract renegotiation costs are involved for generators. Net cost estimates have been quantified in MMA's final report and Appendix A4 of this report.*
• **On-going costs**	*Maintenance of IT systems. Costs have been quantified in MMA's final report and Appendix A4 of this report.*

6. **Impact on NEMMCO systems [refer to questions contained in the 'Aide memoire' appendix of *Assessing the efficiency impact of proposed changes to market arrangements – Draft guideline*] – indicate the extent to which benefits and costs are quantifiable:**

• **What are the implications for the use of NEMMCO systems and operation of processes?**	*NEMMCO would be required to make IT systems modifications to support the new options under consideration. These changes would be in the areas of post processing for dispatch intervals as well as settlement systems.*
• **Once-off benefits**	*N/A*
• **On-going benefits**	*N/A*
• **Once-off costs**	*Costs involved in assessing the options to produce functional descriptions to deliver appropriate IT support systems.* *Costs to make the modifications to NEMMCO dispatch and settlement systems as appropriate. Costs have been quantified in MMA's final report and Appendix A4 of this report.*
• **On-going costs**	*Minor maintenance (support) costs of IT systems. Costs have not been included in the cost benefit analysis because of their small size relative to other cost items.* *Option 2.2 also introduces an element of uncertainty in the delivery of timely 30 minute trading interval price estimates in real time as SCADA data is used as a data source to calculate VWA prices. This risk element has not been costed/assessed.*

7. **Impact on the Code [refer to questions contained in the 'Aide memoire' appendix of *Assessing the efficiency impact of proposed changes to market arrangements – Draft guideline*] – indicate the extent to which benefits and costs are quantifiable:**

• **Is a change to the Code likely to be required?**	*If implementation of either option is recommended, code changes will be required:* *Option 1.1b will require code changes to support the changes to the settlement methodology to manage a settlements imbalance recovery mechanism.* *Option 2.2 will require code changes to support the publication of the VWA trading interval prices as well as a new settlement regime for generators (volume weighted payments weighted against their own generation) and customers (volume weighted against the system demand.*

• **Once-off benefits**	*N/A*
• **On-going benefits**	*N/A*
• **Once-off costs**	*Small net costs are likely to be incurred for a code change process (such as hiring a venue for code change forums). These costs have not been included in the analysis.*
• **On-going costs**	*N/A*
8. Impact on 'the market' [refer to questions contained in the 'Aide memoire' appendix of *Assessing the efficiency impact of proposed changes to market arrangements – Draft guideline*] – indicate the extent to which benefits and costs are quantifiable:	
• **Will the proposal address a perceived market failure? If so, what is the nature and possible cause of the failure?**	*No*
• **What assumptions have been made regarding current and future market behaviour?**	*Bidding behavioural assumptions have been made in MMA's analysis and modelling of the benefits applicable to the options.* *See MMA's final report for an explanation to these bidding assumptions.*
• **Is there any impact on traders / contract market (SRA) participants?**	*These market participants would be impacted through changes to price volatility and the availability and prices for financial market hedge instruments. These issues are discussed in MMA's final report*
• **Are markets (or market segments) being created or destroyed?**	*Both options subjected to detailed analysis may create new competitive sub-markets for short term price responsive generation.*
• **Once-off benefits**	*N/A*
• **On-going benefits**	*Options are intended to address the 5/30 issue – thereby rectifying the inconsistency between dispatch and pricing.*

• **Once-off costs**	*Aggregate costs to the market have been quantified in the "costs" section of this report and summarised in MMA's final report.*
• **On-going costs**	*Aggregate benefits to the market have been quantified in the benefits section of this report and summarised in MMA's final report.*

Stage 4 – Recommendation

1. What is being recommended and why?

Final Recommendations are detailed in this paper. In essence, a "No Change" recommendation has been made following a cost benefit analysis which showed that the benefits in terms of market efficiency, do not outweigh the costs associated with each option.

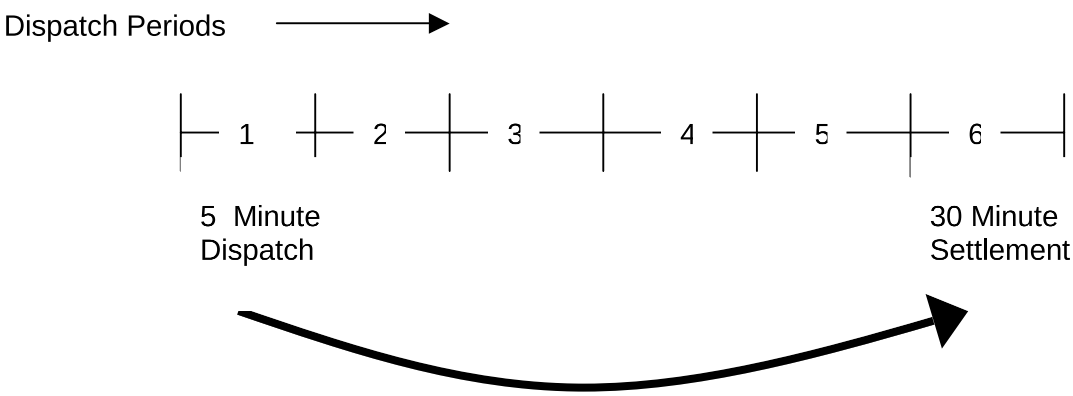
Appendix A6: Description of 30 Minute Aligned Option

Overview:

Completely aligning the dispatch and settlements timeframes eliminates the 5/30 issue as there is then no disparity between dispatch and settlements. This section gives a brief overview of the structure of 30 minute dispatch and settlements. This option was detailed in the Options Paper published by the 5/30 Working Group.

OPTION AREA 1.2 - Aligned Energy Market Dispatch and Settlements at an interval of 30 minutes

Introduce aligned dispatch and settlements at an interval of 30 minutes by increasing the existing NEM dispatch period of 5 minutes to 30 minutes.



Option: 30 Minute Dispatch and 30 minute Settlement

Retains the existing 30 minute settlement cycle, and increases the dispatch interval for energy from 5 minutes to 30 minutes. This means that both the dispatch and settlement intervals for energy are aligned at 30 minutes;

- The boundary between energy and ancillary services would be at the 30 minute level, so that all control functions within the 30 minute dispatch intervals would be transacted as ancillary services. This would include load following within the half hour, including where an interconnector becomes constrained. An augmentation of the new ancillary service arrangements would be required to accommodate this;

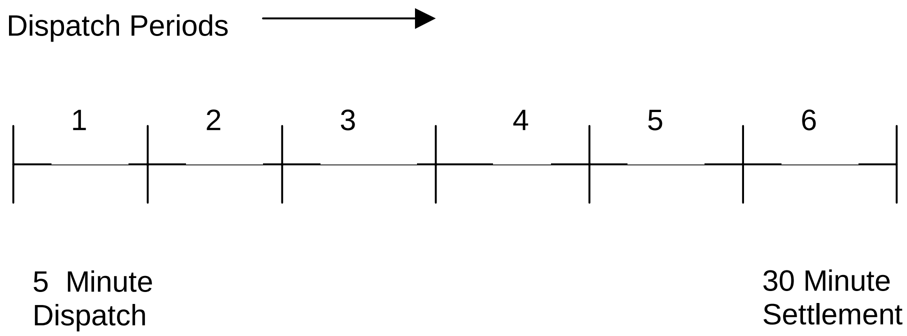
- The SPD dispatch process would operate on the half hour, with a 30 minute look-ahead to provide 30 minute ex ante dispatch and pricing of energy;

- The SPD dispatch process would also continue to operate every 5 minutes within the half hour to optimise the provision of the sub half hour load following ancillary service. This service would take the form of payment for deviation from energy targets. It would initially be carried out with a 5 minute look ahead, but could be enhanced at a later time to optimise inter-temporally if proven to be worth while;

- Existing metering arrangements would suffice for energy trading, however providers of sub half hour ancillary services would need to install 5 minute metering, or otherwise agree to the use of SCADA data for use in settling the service.

Introduction of a new levy/ancillary service to cover the period from 5 minutes to 30 minutes

Coverage of FCAS Ancillary Services in the NEM:



- Existing FCAS only covers the next 5 minute period
- New ancillary service covers the period 5 to 30 minutes

Advantages: 30 Minute Dispatch and 30 minute Settlement

- Directly resolves the 5/30 issue by alignment of dispatch and settlement intervals. Therefore provides clarified investment signals for both supply side and demand side participants;
- Clarifies the boundary between energy and Ancillary Services at 30 minutes. This may assist financial hedge liquidity;
- Provides a form of “look-ahead” in energy market dispatch so that ramp rate limited plant is dispatched earlier than is currently the case to meet foreseeable demand movements;
- Transacts the impact of technical issues such as ramp rate limitations and plant startup times as an ancillary service rather than in the bulk energy supply market;
- Full ex-ante energy pricing at a timeframe more suited to the emergence of demand side response than a 5 minute regime can provide;
- Simplified energy market trading arrangements due to reduction in data;

Disadvantages: 30 Minute Dispatch and 30 minute Settlement

- Moderate to high impact in terms of some implementation issues such as complexity and the requirement for a new ancillary service to be designed, including payment provisions;
- Implementation may require co-ordination with a future stage of FCAS development due to the introduction of further market ancillary services in addition to the current eight;
- Some trading would be transferred from the energy to ancillary service markets. This may cause perceptions of increased ancillary service costs even though overall costs will may have fallen;
- Considerations such as input data quality for dispatch purposes would affect a full half hour of dispatch and pricing, rather than just 5 minutes. Commercial ramifications of such events would therefore be amplified, and new processes would be required to manage this;
- All sub half hour changes, including for example the invocation or revocation of network constraints, or the tripping of a generator, would be transacted as ancillary services until the next half hourly energy cycle, unless special provision was made to re-run energy dispatch within a half hour in extreme cases;
- Progression of this option would effectively represent a paradigm shift in the market, with impacts well beyond solving the 5/30 issue. Evaluation would therefore need to be carried out on a much broader front that the scope of the project would have originally envisaged.