FINAL

Short-term Forward Market

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Prepared by:

Charles River Associates (Asia Pacific) Pty Ltd
Level 31, Marland House, 570 Bourke Street
Melbourne, VIC 3000, Australia
Tel: + 61 3 9606 2800 Fax: + 61 3 9606 2899

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1. EXECUTIVE SUMMARY

This paper discusses different designs for arrangements for a centrally administered contracting regime that operates close to time of dispatch in the National Electricity Market (NEM). Such a scheme is being considered as a means to facilitate greater involvement of demand side resources. The review is being conducted to assess the potential for contracting in this form as an alternative to a proposal in the Council of Australian Governments' 2002 *Energy Market Review* (i.e. Parer Review) for a pay-as-bid scheme. Under a pay-as-bid regime, customers are paid for *not* consuming electricity at times of high prices when the NEM spot price exceeds their bid price for electricity consumption. Such a regime can facilitate price-based rationing of electricity at times of high prices in the NEM.

Currently, contracting is a normal market function between managers of generators and loads to hedge the risk of trading in the wholesale spot market. The market operator, the National Electricity Market Management Company (NEMMCO), settles the spot market but takes no part in the contracting. As result the market operator runs a single "ex post" settlement process based on actual outcomes.

Internationally, other markets for electricity incorporate arrangements for market participants to enter into contracts with the market operator ahead of time. The purpose of these arrangements is to create financial commitments about price, load and generation ahead of the time of delivery and to provide greater certainty for participants facing otherwise variable market conditions. Separate settlements are performed by the market operator for the advance contracting and also for the results of actual market operation. These are termed multi-settlement markets. A small number of multi-settlement markets have previously had two rounds of advance contracting and employ three settlement calculations, one each for the advance contracting and a third for metered actual results.

The design of multi-settlement markets can involve voluntary or mandatory participation in the different steps. If the steps in advance of dispatch are mandatory then the settlement for actual based on actual generation and consumption is to adjust payments for variation from contracted amounts.

The lack of advance commitment to a price in a single settlement market like the NEM can be a barrier to participation of many potential demand response units within the wholesale energy market. This is because operators of certain demand response facilities must make decisions to reduce load many hours in advance — for instance, to reschedule the timing of energy intensive production activities. In single settlement markets there may be considerable uncertainty about the market price this far in advance and this uncertainty limits the number of parties willing to participate as they are reluctant to lose production only to find the ex-post market price was below their ex-ante expectations. The technology employed in other forms of demand side response require less notice and customers are able to respond immediately under contracts established further in advance. For these customers, short-term contracting is of less value.

Ideally, the existing bilateral contracting arrangements in the NEM could provide the certainty equivalent to that from a multi settlement arrangement. However, in practice it can be difficult for parties who have not entered into contracts well in advance to achieve new commitments in the 24 hours before dispatch. This is firstly because of the need to identify the circumstances where market price will be high enough to warrant changing production schedules and then to identify potential buyers and execute contracts. As a result, demand managers have limited commercial incentive to make the necessary internal commitments and retailers are driven to be conservative in contracting with them because of the risks of guaranteeing a price for a demand reduction that may in the end be "out of the money".

At the time the NEM was being developed, consideration was given to introducing a multi settlement design. This was rejected by the ACCC on the basis of concerns about a centrally operated scheme potentially "crowding out" other providers and the potential conflict of interest that NEMMCO would face if it was both market operator and was to take a position in the short-term contracting. In practice, no external providers have emerged to establish a short-term contracting exchange, although there have been a number of schemes for longer-term contracting. Whether NEMMCO has a conflict of interest or not is dependant on the detailed design of the regime, which could be arranged to ensure that conflicts do not arise.

There is thus scope for a centralised regime to facilitate short term contracting. Such an arrangement could, however, have a range of objectives. It could, for example, be a simple adjunct to existing market arrangements. Alternatively, it might involve more fundamental changes in the risk management environment for trading, by providing for contracts based on the outcome of the day-ahead pre-dispatch published by NEMMCO. This would reflect expected network performance and place greater emphasis on the accuracy of demand forecasts by NEMMCO. In some multi-settlement markets, loads are responsible for submitting estimates of load to the market operator — rather than the market operator making estimates on their behalf — and the advance contracting process results in financial commitments for loads based on those estimates. Although not without merit, this is more far reaching than facilitation of demand side participation alone.

Short-term forward markets in general provide advance financial commitments of one form or another. However, where such markets have been introduced, the reasons for seeking advance commitments have been quite varied. Short-term forward markets have been developed to address management of inter-pool trade where it is logistically necessary to provide advance notice of intended transfers to adjoining markets with different market rules and/or power system controllers. This is not an issue in the NEM as it is a contiguous market. Within Australia, certainty about start up and shutdown of generating units was, in the early days of development of competitive markets, a matter of concern and resulted in centralised unit commitment arrangements within the market rules and could otherwise be assisted by a short-term day-ahead market. In practice the NEM has dispensed with these arrangements and we understand is working satisfactorily. The integration within the real-time dispatch of arrangements for ancillary services and energy in the NEM has tackled a driver for the establishment of a multi-settlement market in the Pennsylvania–New Jersey–Maryland (PJM) market in the US within a single settlement design. As a result a number of the reasons for needing advance financial commitments possible from a short-term forward market are not (or no longer) present in the NEM.

However, resources other than demand side facilities may also obtain benefit from increased advance financial commitment. In general these are plants that rely on fuel from external sources with little opportunity for storage, including some hydro units and gas-fired plants that are dependant on external producers and transporters. These plants will generally have established links with retailers in the wholesale market. Therefore, they are better equipped than smaller demand side participants who may participate only occasionally in the wholesale market but may nevertheless obtain incrementally better contracting opportunities through a short-term centralised facility. Network operators subjected to incentive arrangements for the availability of their plant might also see advantages in a more stable short-term price in order to plan their operations.

A final matter to consider in deciding on the value and form of a short term contracting arrangement to facilitate demand side is that participation of demand side resources potentially can add value in each of the retail, distribution, transmission and ancillary service segments of the NEM as well as the wholesale energy market. The same resource may have value in each of the segments. In addition, there has been considerable effort by regulators, market participants and more recently by private aggregators both to overcome institutional barriers and to assemble commercial propositions. Improving opportunities for participation in one segment may lead to improvements in another. For example, changes in network tariffs to manage peaks in network loading may result in additional resources being brought directly into the energy market or made available to retailers to manage demand outside of the wholesale market.

On this basis:

- There is scope to further improve institutional and regulatory arrangements for participation of demand side resources in the NEM;

- There is currently limited ability for managers or agents of demand side resources where advance notice (in the order of 12 –24 hours) is required, to obtain certainty of price;

- A simplified short-term contracting arrangement that supplements existing contracting between market participants would offer an avenue for demand managers to obtain price certainty in the short term. This could be conducted by a range of parties, although there would be advantages in integrating settlement with the NEMMCO spot market settlement; and

- There does not appear to be evidence for a more sophisticated arrangement integrated with pre-dispatch. In particular, several of the reasons that led to the establishment of multi-settlement processes in other electricity markets have been addressed by other features of the NEM. For example, generator self-commitment and integration of ancillary services dispatch with the energy market.

2. INTRODUCTION

2.1. BACKGROUND

The South Australian Department of Treasury and Finance (SADTF) has commissioned Charles River Associates (Asia Pacific) Pty Ltd (CRA) to prepare a discussion paper on the possible benefits and implications of moving from a single-settlement to a multi-settlement process in the National Electricity Market. A multi-settlement process involves load and generation offering into a day-ahead and/or hour-ahead electricity market; with each market being settled on the basis that such offers are firm financial commitments. That is, after the offer closing time for the day-ahead/hour-ahead market, all bids and offers accepted by the market operator are settled. The effects of settlement of final dispatch are then used to adjust for any unders and overs in the real-time dispatch relative to the day-ahead and hour-ahead settlement positions of market participants.

By having multiple-settlements, a short-term forward market (STFM) is created in which market participants can seek to trade short-term contracts in order to manage risks by rebalancing their positions, and take advantage of any arbitrage opportunities between the day-ahead, hour-ahead and real-time markets.

The 2002 Council of Australian Governments' (COAG) Energy Market (Parer) Review recommended that NEMMCO introduce a 'pay-as-bid' mechanism for load reduction into dispatch and pool price setting to encourage demand side involvement in the National Electricity Market (NEM).[1]

The introduction of a short-term forward market, utilising a multi-settlement approach instead of the NEM's current single settlement procedure, may offer an alternative to the Parer Review's 'pay-as-bid' mechanism for facilitating demand side response; and might have additional benefits for the economic efficiency of the market and the ability of participants to manage risks.

Multi-settlement is used in a number of overseas markets, such as PJM. Although a short-term forward market was rejected by the Australian Consumer and Competition Commission (ACCC) in authorising the National Electricity Code (Code); after five years' experience with the NEM, now might be the time to re-consider the relative merits of setting up such a forward market by introducing multi-settlement.

2.2. OBJECTIVE AND SCOPE OF WORK

The terms of reference requires that the consultant:

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[1] Recommendation 6.1 of Council of Australian Governments (2002), *Towards a Truly National and Efficient Energy Market*, Final Report, COAG Energy Market Review (Chair: Mr Warwick Parer), AusInfo, Canberra.

- Prepare a high-level discussion paper that identifies the benefits and implications of a multi-settlement market, in particular:
  - Identify the benefits and implications of a multi-settlement market within the NEM;
  - Suggest how such a market could be designed and implemented, including recommendations/options; and
  - Provide recommendations/options supporting user participation and demand side management more generally, including those from the user participation working-group, in such a market.

2.3. STRUCTURE OF THE REPORT

The report is structured as follows:

- Section 3 outlines the different forms of settlement and the operation of multi-settlement in the context of the market designs of the PJM and New England electricity markets;
- Sections 4 discusses the potential advantages of a multi-settlement system;
- Section 5 examines the efficacy of the NEM's existing mechanisms for price discovery and balancing supply and demand;
- Section 6 reviews why multi-settlements processes were implemented in the PJM and New England electricity markets and assesses whether the claimed benefits of multi-settlement would necessarily translate into the NEM, which has a fundamentally different market design to the PJM and New England markets;
- Section 7 examines the existing arrangements for demand side response and the likely effects of multi-settlements on the level of demand side response in the NEM;
- Section 8 reviews the ACCC's rejection of National Electricity Code clause 3.10, which proposed a more ambitious short-term forward market than that contemplated in this report;
- The proposed design and implementation of a short-term forward market based around multi-settlement is set out in Section 9; and
- A summary and conclusions are in Section 10.

3. DIFFERENT FORMS OF SETTLEMENT

Electricity market designs can be characterised in a number of ways, including:

- Single Settlement or Multi-Settlement. This refers to the number times financial settlements occur in the market — once, based on real-time dispatch; or more than once, using prices and volumes cleared in a market prior to real-time, followed by another settlement based on real-time dispatch;
- Voluntary or compulsory participation;
- Bilateral trading or Pool;
- Gross Pool or Net Pool – whether settlements are based on the total (or gross) energy traded in the market or only the energy not traded under contract and is thus the net of total and contract volumes;
- Centralised generator unit commitment or self-commitment. Unit commitment is the process of determining which generators should be operated each day to meet the daily demand on the system;
- Locational Marginal Pricing (LMP, which can be nodal or zonal) or uniform pricing;
- Co-optimised energy and ancillary services markets, or separately dispatched energy and ancillary services;[2]
- Those with capacity payments and energy-only markets; and
- Markets where dispatch and pricing are aligned together with settlements and those where dispatch, pricing or settlements might not all be aligned.

The National Electricity Market's design characteristics are: single-settlement; compulsory trading; gross pool; self-commitment; zonal LMP; co-optimised energy and frequency control ancillary services; energy-only; with an alignment between dispatch, pricing and settlements.

The choice of whether Single Settlement or Multi-Settlement is used is, like other market design choices, related to the:

- Historical operation of each electricity system prior to the implementation of a market;

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2 *Co-optimisation* involves solving the mathematical problem of finding the levels of dispatch of energy and ancillary services, which together give the least-cost solution. Dispatch arrangements that do not use co-optimisation typically set the level of ancillary services first and then determine energy dispatch.

- Way in which unit commitment is carried out; and
- Speed at which the market is allowed to evolve away from past, utility-based, operations and procedures or financial trading arrangements.

Historically, in systems with a large proportion of thermal generation, central commitment was used to minimize start-up and shutdown costs and to ensure sufficient capacity reserves to meet real-time changes in load or generation. The solution of this central commitment problem required generators and loads to submit bid and offer schedules, which were used in calculating the week-ahead or day-ahead unit commitment.

Markets with centralised unit commitment often had week-ahead and day-ahead prices related to the solution of the unit-commitment problem.

These prices could be and were used by utilities for managing unit-commitment risk, scheduling sufficient generation to match any contracted load, and discovering energy prices. These prices evolved to be used for inter-utility energy trading in day-ahead markets, with the real-time price being used for all settlements. Alternatively, the day-ahead price was used to settle dispatched day-ahead bids and offers, with the real-time price used to settle any additional capacity dispatched in real-time. This additional capacity would either provide ancillary services or account for changes in load and generation closer to real-time.

The speed of market evolution affects whether central commitment or self-commitment is used. Central commitment involves power system operators solving the least cost optimisation problem of scheduling generators and/or controllable loads a day or more *before* real-time dispatch. This ensures sufficient resources will be on line to balance electricity supply and demand, allowing time for unit start-up and other physical constraints. Self-commitment involves decentralised decision making about when to schedule generation start-up and shut down, with each generator's preferences being signalled to the system operator via its offer price, quantity, and operating constraints.

Initially in VICPOOL[3], central commitment was used, but this changed over time as market evolved to a self-commitment model.

Concerns about moving away from centralised unit commitment were one the reasons why early VICPOOL, NEM1, and NEM designs had either specific short term forward markets or central commitment.

3 VICPOOL was the electricity market run by the Victorian Power Exchange (VPX) that operated in Victoria from 1994 to 1997. A similar market, called SEM, was operated in New South Wales by TransGrid. These two state-based electricity markets were integrated to form NEM1, the precursor of the NEM.

In a number of US electricity markets, the move towards fully functioning markets has been limited by the degree to which market participants are able to accept fundamental changes to past practices. Consequently, many US electricity markets have retained central commitment, day-ahead markets and real-time markets.

The next two sections discuss single settlement and multi-settlement.

3.1. Single Settlement

Single settlement involves settlement of all dispatched energy based on prices from real-time dispatch, using either net or gross amounts.

Single settlement is currently used in the NEM, Ontario and New Zealand electricity markets. It was originally used in the PJM and New England electricity markets and the initial England &Wales pool market.

3.2. Multi-Settlement

A multi-settlement process involves load and generation offering into a day-ahead and/or hour-ahead electricity market; with each market being settled on the basis that such offers are firm financial commitments.[4] That is, after the offer closing time for the day-ahead market, all bids and offers accepted by the market operator are settled. The settlement outcome of final dispatch is then used to in effect adjust for any unders and overs in the real-time dispatch relative to the day-ahead and hour-ahead settlements positions of market participants at some form of spot price.

3.2.1. Two-Settlement

Two-settlement involves separate settlements for day-ahead contracting and real-time dispatch. Two-settlement is currently used in the PJM and New England electricity markets.

3.2.2. Three-Settlement

Three-settlement involves separate settlements for day-ahead contracting, hour-ahead contracting, and real-time dispatch. At present, no market uses three-settlement.

Table 1 sets out the design characteristics of the PJM, New England and Ontario electricity markets and compares them to those in the NEM.

4 In this case, a *firm financial commitment* is one where parties whose bids and offers are accepted by the market operator are obliged to be paid or pay for the market clearing volumes at the market clearing prices.

Table 1: Design Characteristics of Selected Electricity Markets

	Energy Market	Capacity Market	Regulation Market	Spinning Reserve Market	Settlement
PJM	Day ahead & Real-time	Day ahead & Real-time	Day ahead & Real-time	Day ahead & Real-time	Two-settlement
ISO New England	Day ahead & Real-time	Day ahead & Real-time	Advanced of Real-time but not day-ahead	Advanced of Real-time but not day-ahead	Two-settlement
Ontario IMO	Real-time	None, energy-only	Real-time	Real-time	Single-settlement
Australia NEM	Real-time	None, energy-only	Real-time	Real-time	Single-settlement

Further information on the PJM and New England markets is outlined in Appendix A.

4. POTENTIAL ADVANTAGES OF A MULTI-SETTLEMENT SYSTEM

Multi-settlement markets involve a financial commitment to settle accepted day-ahead or hour-ahead bids and offers in advance of real-time dispatch, when load and generation capability is known precisely. This can create strong financial commitment incentives to meet pre-commitments and result in price stability and flexibility.

4.1. STRONG INCENTIVES TO MEET PRE-COMMITMENTS

The binding financial commitments on a multi-settlement market can provide strong financial incentives for:

- Generators and demand side participants to submit day-ahead offers and bids that match their actual willingness to commit;
- Wholesale users to understand and manage their patterns of consumption; and
- Generation or demand side participants to follow real-time dispatch. Failure to do so results in them having to purchase off the spot market to meet their day-ahead financial settlements.

This occurs because participants who commit in a forward market are able to 'lock-in' day-ahead scheduled quantities at day-ahead prices, and thus reduce their vulnerability to price fluctuations in the real-time market. While this provides protection against price increases on the day, it also inhibits exposure to occasions when prices are lower. Consequently, the day-ahead price signals influence correct, economic rationing and real-time behaviour.

Of particular interest in this context is the response that other parties may have to price exposure through the NEM pre-dispatch process and who might therefore bring additional capacity to the market. Conversely, parties may also utilise the rebidding arrangements to push price up where they have the market position to do so.

4.2. INCREASED PRICE STABILITY AND FLEXIBILITY

The existence of a day-ahead market with binding financial commitments has the potential to increase price stability. This occurs because day-ahead prices will tend to be less volatile than real-time prices since physical power system events which drive 5-minute price volatility are not present in day-ahead markets. Examples of volatility price drivers at the 5-minute dispatch level are: dispatch errors, unit non-conformance, ramp rate limits, demand forecast errors, and contingencies. Note this does not suggest day-ahead prices will necessarily be lower than real-time prices.

Price stability will also be aided by the potentially greater transparency facilitated by the short-term market. Arguably the lack of opportunity to acquire acceptably priced contracts at short notice has impeded the functioning of the electricity market. A published short-term price would provide a clearer indicator of short-term bidding behaviour and potentially discipline it, relative to existing arrangements in the NEM.

A STFM could also provide greater flexibility to market participants because it would provide them with a broader range of short-term contractual options than available at present. To the extent that these options are taken up by participants, the short-term contract market will become more liquid, more competitive, and more economically efficient.

Finally, the presence of multi-settlement can reduce the level of risk faced by participants because there are two opportunities to cover load or match generation to contracted volumes — day-ahead and in the period immediately prior to dispatch.

The next section discusses the efficacy of the NEM's existing mechanisms for price discovery and balancing supply and demand, which precedes discussion on whether and how a multi-settlement process could be introduced into the NEM.

5. EFFICACY OF THE NEM'S EXISTING MECHANISMS FOR PRICE DISCOVERY AND BALANCING SUPPLY AND DEMAND

To varying degrees many of the price discovery and supply-demand balancing functions that a multi-settlement process would facilitate are provided by the MT-PASA, ST-PASA and Pre-Dispatch processes in the NEM. However, these arrangements, while requiring mandatory data from participants, involve no financial commitment. Data about physical plant status is used by NEMMCO to conduct assessments of future power system reliability, but in effect this data is provided to NEMMCO on a good faith basis. The price information in Pre-Dispatch is open to significant adjustment as a result of the re-bidding process and 'normal' variability in demand and generation capability.

A transparent price discovery process can enable market participants to manage and adjust their risk exposure and result in an economically efficient balance between committed generation and expected demand, with minimal intervention by the power system operator.

5.1. EXISTING PRICE DISCOVERY PROCESS

The existing spot price discovery mechanism in the NEM comprises:

- *Medium-Term Reliability Assessment (MT-PASA)*[5] — which publishes information at least every week on the daily Supply-Demand balance in each region going forward two years;
- *Short-Term Reliability Assessment (ST-PASA)*[6] — which publishes information at least every two hours on the half-hourly outlook of expected demand and generation availability going forward one week. ST-PASA information includes:
    - generation that could be made available with 24 hours notice;
    - generation plant that is planned to be operating and fast-starting generators (i.e. those with a less than 30 minute start-up time); and
    - forecast demand levels (expected, high, and low demand), by region and half-hour;

5 MT-PASA — Medium Term Projected Assessment of System Adequacy.

6 ST-PASA — Short Term Projected Assessment of System Adequacy.

- *Pre-Dispatch* — published every 30 minutes with approximately a 1-day ahead outlook of 30-minute demand, price and generator availability; together with price sensitivities for variations in load. Pre-dispatch prices are calculated based on bids and offers submitted by market participants; and

- *5-Minute Pre-Dispatch* — published every 5 minutes with a 1-hour ahead outlook of demand and price for each 5-minute interval.

The information from the medium- and short-term reliability assessments (MT-PASA, ST-PASA) and Pre-Dispatch is used by market participants in the following ways:

- *MT-PASA* — used for maintenance scheduling as it assists in identifying the best times to schedule maintenance (that is, when reserves are high);

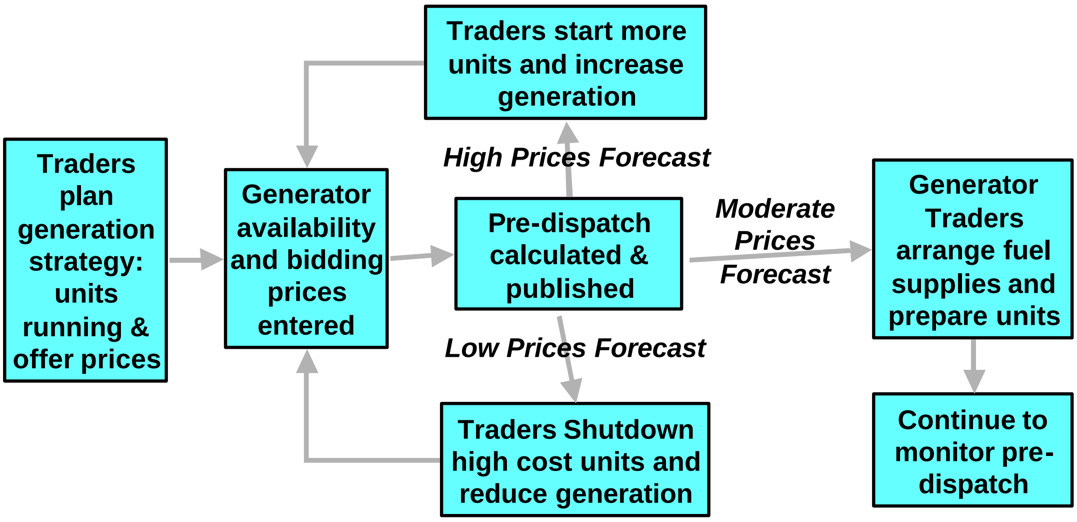
- *ST-PASA* — used for commitment of plant, especially gas-fired plant. Generator traders (or scheduled loads) submit availability and operating plans to NEMMCO. The information in ST-PASA assists in identifying the best times for running plant or scheduling short-term maintenance;

- *Pre-Dispatch & 5-Minute Pre-Dispatch* — the pre-dispatch provides market participants with information on what their dispatch is likely to be and the spot price. Participants use this information to adjust their bids and/or offers to match their contract positions, minimize dispatch risk, and optimise financial outcomes — that is, to decide whether of not to re-bid prior to real-time dispatch.

  Traders use the pre-dispatch information to optimise their generation (or scheduled demand side offer) by an iterative process (see Figure 1) in which they:

  - Plan if and how plant will be bid (or offered) into the market;
  - Bid (Offer) in plant;
  - Observe Pre-dispatch;
  - Review plan;
  - Re-bid, if necessary;
  - Observe Pre-dispatch; and
  - Review plan.

Figure 1: Use of Pre-dispatch Information in Generation Scheduling and Bidding



The pre-dispatch process is the only one in which forecast prices and price sensitivities are published. However, the MT-PASA and ST-PASA data provides useful information around which commitment decisions can be made and allows views to be formed on the likely level of prices, based on the supply-demand balance and expectations of competitors bidding behaviour.

The NEM's existing spot price discovery process can be characterised as follows:

- Prior to 24 hours to dispatch, market participants lodge bids and offers which are generic, and usually with a fairly stable structure;

- At around 24 hours to dispatch, as Pre-dispatch information becomes available, market participants begin to refine their bids and offers to maximise their returns under the predicted energy balance conditions by attempting to influence their dispatch price and volume. The re-bidding associated with this can create increased volatility in pre-dispatch prices, that is reflected in the pre-dispatch price sensitivities; and

- As dispatch time draws closer and more information comes to hand (e.g. revised load forecasts), re-bidding continues until such time that pre-dispatch price might stabilize towards an equilibrium state that reflects the final state of information prior to dispatch.

Although this process allows spot prices to be discovered, the margin for error around expected prices can be significant, resulting in:

- Greater dispatch risk, which gets priced into wholesale contracts; and

- Difficulties in committing plant, particularly gas-fired plant and demand side response. If expected high prices do not eventuate or last for only a short period of time, then significant costs can be incurred by plant that commits.

5.2. EFFICACY OF NEM'S EXISTING PRICE DISCOVERY PROCESS

The efficacy of the NEM's existing price discovery process can be assessed against how well it:

1. Provides short-term economic signals regarding:
   - scarcity value related to imbalances in supply and demand;
   - when to commit plant;
   - the circumstances under which it is profitable to offer capacity into the market;
   - likely revenue that will be received if dispatched;
2. Facilitates short-term rebalancing of spot and contract portfolio positions, and hence the reallocation of risk close to real-time dispatch; and
3. Indicates of power system reliability and security.

The volume of information published in the NEM has led some (including regulators) to raise concerns about whether the strategic bidding and re-bidding associated with the spot price discovery process increases the possibility that market power will be abused.

NECA and the ACCC have raised concerns that because a market participant has access to detailed information, it might attempt to exercise market power when: demand is high, it can see that a competitor has had a plant breakdown, or when transmission outages have limited the degree of competition. Concerns have also been expressed that a generator might deliberately mislead the market for financial gain. For example, a trader might bid sufficient volume in at a low price band (or as must-run plant) that it depresses the regional price forecast. In response to the forecast low prices, other generators might shutdown; after which time, the first trader re-bids its capacity into higher price bands when it is apparent that there will be less competition about. In doing so, the generator might for a time be successful in driving up the regional price above competitive levels and capturing any economic rents associated with the higher price.

Since the start of the NEM there have been a number of NECA and ACCC investigations of bidding and re-bidding behaviour. These investigations have pointed to the impact such behaviour can have in inducing high prices in energy and ancillary services markets and the resulting political fall-out.

The Code has been amended to require bids and other information to be provided in good faith, but proving that this requirement has been breached is likely to be extremely difficult.

The reason that the existing NEM price discovery process was authorised is that participants and the ACCC considered that the risks posed by information disclosure in the NEM's price discovery process — together with re-bidding — were outweighed by the benefits, which include:

- The market self-corrects when there are low reserve conditions — that is, supply and demand can respond to forecast shortages by committing capacity;
- Traders can optimise generation by shutting down expensive units that are unprofitable and starting up units to take advantage of higher prices. In doing so, market forces help drive productive efficiency;
- There is a competitive response to forecast high prices, with prices stabilising close to dispatch — often at lower levels than through the pre-dispatch process;
- Generators being able to make cost-minimizing plant commitment and fuel supply nomination decisions. This is important in a self-commitment market like the NEM;
- Reserves can be monitored by market participants, NEMMCO and jurisdictions. This allows time for a market response to any shortfalls and reduces the likelihood of market intervention, either by NEMMCO or by the jurisdictional government; and
- Potential improvements in contract market efficiency and the level of contract market competition because contract traders are more informed of spot price dynamics.

5.2.1. Short-comings of Existing Arrangements

Arguably, the shortcomings of the NEM's existing arrangements for balancing supply and demand, signalling short-term reliability, and signalling short-term prices, include:

- *Difficult to commit demand side response* — Under existing arrangements it is hard to arrange certain types of demand side response (i.e. the type that requires significant notice to commit) because of uncertainty concerning the final settlement price; and – arguably – under existing arrangements the volume of demand side response is limited to the type that is prepared to respond at short notice to an uncertain settlement price. It is notable however that recent work within the industry is seeing increased potential for demand side that does not require significant notice. If there were greater certainty surrounding the settlement price, together with a greater notification period for the commitment of demand side response, then it is likely that a larger range of demand side response might choose to participate in the wholesale market. This has the potential to improve the economic efficiency by rationing resources at times of scarcity to those most willing to pay; and

- *Difficult and/or expensive to adjust bilateral contract positions close to real-time* — At present, within a day of real-time dispatch, there is no ready facility to match buyers' bids and sellers' offers for the incremental volumes that need to be traded to balance out a contract position. Instead, market participants either wear the costs of being incrementally over- or under-hedged, or pass these costs on to their customers.

When there are significant misalignments in bilateral contract positions, this leads to an economically inefficient allocation of risk, whereby:

- risk is forced on to parties with a lower appetite for risk and/or a lower ability to manage it because there is an inability to trade the full range of risk instruments at the times when they provide value. That is, there is a lack of liquidity[7] in short-term instruments, which forces parties to bear risk; and

- the costs of managing risk across the combined spot and contract markets might be higher than they would be if short-term contract positions could be adjusted closer to dispatch. For example, there might be increased reliance on credit support — either from parent companies or financiers. The costs of such credit support might exceed the potential cost of short-term risk management instruments available in a short-term forward market.

However, the allocation of risk under existing arrangements would be expected to depart little from that arising from an efficient risk market if the:

- magnitudes of any misalignments in bilateral contract positions are small; and

7 Liquidity is about the ability of market participants to trade a full range of risk instruments at the times they desire. Market liquidity is separate to the issue of whether there are sufficient volumes traded to satisfy the desires of participants. A contract market may be liquid, but not trade in the volumes desired.

- risk-adjusted cost of self-insurance (or credit support) is lower than the cost of short-term risk management instruments.

6. IMPLEMENTATION OF MULTI-SETTLEMENT PROCESSES IN OVERSEAS ELECTRICITY MARKETS

PJM and New England are two examples of electricity markets where multi-settlement is operating — apparently successfully. These markets have a lot in common. Both employ a capacity mechanism and central unit commitment and at the time multi-settlement was introduced, any moves towards a self-commitment (or energy only) market were seen as too radical given the history of the previous central commitment pools.

Interestingly both the PJM and New England electricity markets initially operated with a single-settlement procedure. However, problems arose at times of high demand when insufficient reserves were being committed for ancillary services, primarily because ancillary services markets were not co-optimised with energy markets. Consequently, market participants would wait until close to real-time to commit to ancillary services markets because at that stage they would have a better view of the opportunity costs of providing ancillary services versus energy, and they would know whether their energy bids were going to be dispatched.

In summer 1998 in PJM and in the early part of New England market (1999-2000), this 'wait–and–see' behaviour led to reserve shortfalls and intervention by system operators to ensure adequate reserves. This intervention involved the withdrawal by the system operator of capacity from the energy market to provide reserves — driving up the energy price significantly. At times in 1998, reserve shortfalls in PJM led to involuntary load shedding as the system operator sought to maintain power system security and reliability.

These initial difficulties with the operation of the PJM and New England electricity markets led to calls for improvements in:

- The way scarce capacity was rationed;
- Price signalling of energy and ancillary services;
- Incentives on generation and demand to commit to energy and ancillary services markets; and
- The way the energy price was linked to the prices of ancillary services (i.e. co-optimisation of energy and ancillary services).

The implementation of multi-settlements was seen as a key step towards achieving the first three of the above improvements, and in 1999 PJM began implementation, with New England shortly afterwards. This was followed by moves to shift the procurement of ancillary services by the respective system operators to a more economically rational basis.

Implementing ancillary services co-optimisation would have been an alternative means of improving capacity rationing, but in 1999 and 2000 that was seen as too ambitious for the newly established PJM and New England electricity markets.

The ancillary service that interacts most strongly with the dispatch of energy is frequency control ancillary service (FCAS). Energy and FCAS have been co-optimised in the NEM since late 2000 when market ancillary services were introduced. Before then the NEM employed a regime of compensation for lost opportunity in the energy market for participation in ancillary services and did not experience the withholding of ancillary services (or reserves) that was seen in PJM and New England.

As noted, both the PJM and New England markets also employ a capacity payment of some sort. Due to capacity payments in these markets, buyers and sellers are not as reliant on volatility in the real-time market price for the recovery of fixed costs compared to an energy-only market such as the NEM. As a result, participants may be more willing to enter into short-term contracts than in an energy-only market. This may reduce the preparedness of parties to use a STFM as to do so they lose the opportunity to gain from, or possibly create, volatility in the real-time market. This opportunity cost has to be balanced against the potential to secure high prices that appear in the day-ahead outlook but which may not eventuate in real-time when additional capacity comes into the market in response to that outlook. Demand side response is likely to fall in this category as discussed in Section 7.

6.1. Whether The Same Role Is Applicable To The NEM's Energy-Only Market Design

A consideration in the initial design of a STFM for the NEM was the expectation that base load generators would require a clear understanding of contract positions the day ahead of real-time dispatch in order to firm up unit commitment. In practice the NEM has not had a STFM but base load unit commitment has not been an issue. This is probably due to the relative amount of base-load plant compared to demand (whereby this plant is generally able to contract bilaterally) and a general level of comfort with the self-commitment process.

Within the market, generators need to set the level of contracting to balance:

- Commercial interest in locking in revenue;
- Risk exposure created by plant performance. For example, the risk that their plant will suffer a breakdown but financial contracts will still need to be honoured;
- Limitations on arranging short-term bilateral deals to cover plant breakdowns; and

- Up-side financial opportunities arising from volatility in the real-time market.

STFM as a Substitute for Short-term Bilateral Contracting

As generators' level of certainty about plant availability increases closer to the time of dispatch, the presence of a centralised STFM would assist in overcoming existing limitations in short term bilateral trading that might be inhibiting higher levels of contracting. Although a STFM would increase the potential for contracting, its use would be a matter of behaviour and strategy. Later we have recommended that the design of the STFM and possible behaviour in it be tested using a "game" similar to that used for training prior to the start up of the NEM.

Generator Benefits

The sub group of generators that need to arrange in advance for fuel, labour or co-generator[8] operation are likely to benefit the most from the opportunity to firm up prices a day ahead. For example, gas or hydro power stations must be given advance notice to ensure that they have adequate fuel supplies (e.g. gas transport nomination, air space in a dam or an increase to a river flow). These generators would have the opportunity 'lock-in' the price that they would receive in return for incurring the expense of securing the availability of fuel. Currently, there is a risk that physical and commercial conditions for the following day may be forecast to have a sufficiently high price that it is appropriate to arrange for the fuel; but in the end conditions change and the actual price in the market is much lower. When this occurs, the generation or demand side will not be called or will receive a much lower price. This is an example of the market responding to forecasts in the correct direction, but possibly overly so. That is, the market 'overshoots' or 'undershoots'. The result is that a plant with this type of fuel constraint does not present to the market or adds a risk premium to its price. This type of response can, in fact, be the most efficient answer when other plants respond— but can also be wrong if the price remains high. Given the lag times for decisions, this is an unavoidable risk in the industry. A STFM would allow such a generator or demand manager to offer the price at which it was prepared to commit to the fuel expense. Buyers could bid the price they would be prepared to pay to lock-in a day ahead price, knowing that there is a risk it might rise or fall.

8 A *cogenerator* is a power plant that generates both electricity and heat, with the heat being captured and typically used in an industrial process or for space heating. Cogenerators are also referred to as Combined Heat and Power (CHP) plants.

Alternative STFM–like Structures

We would also note that attempts by the Australian Stock Exchange (ASX) and Sydney Futures Exchange (SFE) to establish centralised contract regimes have been, at best, marginally successful. However, these have been for products with time horizons far longer than would ever be considered for a STFM. They were in effect substitutes for medium term contracting; whereas the STFM would mimic very short term contracting and have a quite a different role in the management of risk than medium term contracting.

Demand Side

The volatility of the NEM spot market is also a driver for greater interest in demand side response. It is in this area that a STFM may have the greatest application. This issue is addressed in a Section 7.

Summary

In summary, the reasons multi-settlement could be less useful to the NEM's energy-only market than other markets include:

- Exposure to price volatility is an important contribution in the recovery of fixed costs in the NEM, and as such participants may be less willing to enter into short-term contracts than participants in a market with capacity payments;
- The NEM already has ancillary services co-optimisation, which reduces the likelihood of some of the reserve scarcity problems that arose in PJM and New England that led to calls for multi-settlements;
- The NEM is an information rich electricity market, compared to most others. For example, in the NEM pre-dispatch price sensitivities, are released close to dispatch and generator bids are published the day after dispatch. In other electricity markets such information may not be published at all, or only be released monthly after dispatch; and
- Financial Contracts for Differences (CfDs) — i.e. swaps and caps — already place strong financial incentives for generators and scheduled loads to commit.

6.2. DIFFICULTIES WITH AND ARGUMENTS AGAINST A STFM

This section briefly notes the problematic issues and complexity that may hinder agreement on the establishment of a STFM. These include:

- Algorithm development — the STFM may add another layer to a market with co-optimised energy and ancillary services;

- Settlements system changes;
- Transition of existing contractual arrangements; and
- Prudential requirements for participants in the STFM that impose additional costs on market participants.

Most of these difficulties are surmountable. However, not all market participants would see a positive benefit in a STFM. For example, for some participants, the advent of greater demand side response or reduced price volatility brought about by a greater use of short-term contracting would result in a reduction in asset values (e.g. peaking capacity) or the value of financial contracts. Consequently, they might oppose the change.

In the absence of a multi-settlement process, NEM rules and participant risk management processes have evolved to manage some of the issues relating to price signalling, risk allocation, self-commitment, and demand side response.

Therefore, market participants are likely to need convincing that:

- A move to multi-settlements represents an improvement over the existing single-settlement arrangement;
- The cost of implementation is worth the benefits, particularly if they themselves do not benefit; and
- The new arrangements will not introduce perverse incentives that might increase the costs or risks they face.

7. IMPACT ON DEMAND SIDE RESPONSE

Since the start of the NEM in 1998, concerns have been raised about the relatively low level of demand side involvement in the market. There are a large number of issues affecting the level of demand response, including the design of tariffs and Code conditions for those on the demand side of the market wishing to bid into the market. However, the lack of a means for retailers or other purchasers of demand side response to realise a revenue stream that they might use to underwrite a deal with demand side mangers has been reported as one reason for low take-up. The lack of a short-term forward market mechanism in the NEM is viewed by some as a significant impediment to greater demand side response, and to the economic benefits that could arise if there were greater demand–side response at times of peak load.

7.1. EXISTING ARRANGEMENTS FOR DEMAND RESPONSE IN THE NEM

The NEM's energy-only spot market – when combined with contracts for differences (CfDs) – produces strong incentives for generators to meet their contract obligations. Failure to generate adequate volumes of energy results in generators being exposed to financially binding difference payments, which they might have to meet through pool purchases at a higher cost than that at which they could generate, thereby reducing or eliminating the profitability of the CfD contract. This combination of the energy-only spot market and CfDs creates similar incentives for generators to deliver energy in real-time as would a multi-settlement market.

In contrast, the present NEM arrangements do not create strong incentives for demand side participation in the market, and particularly not for participation as a scheduled load. The impediments to demand side resources acting as scheduled loads are well-documented and include: the requirement to provide a minimum load reduction of 30 MW, the requirement for pool exposure, and the need to meet prudential requirements and other technical requirements related to control and measurement of the load.[9] Impediments to demand side participation on a non-scheduled basis include:

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9 See, for example:

IPART (2002), *Inquiry into the Role of Demand Management and Other Options in the Provision of Energy Services*, Final Report, Review Report No. Rev01-02, Independent Pricing and Regulatory Review Tribunal of NSW, Sydney, October.

CRA (2003), *Information Paper: Embedded Generation in SA*, report for Electricity ESCOSA, Essential Services Commission of South Australia, Adelaide, November.

ESC (2004a) *Guideline for Embedded Generation: Final Decision*, Essential Services Commission, Melbourne.

- uncertainty about the final price that applies for a given settlement period — which makes demand response that requires lead time to arrange more risky;
- the potential for the delivered demand response to change the pool price and thereby reduce the benefit received from the load reduction;
- the uncertainty of the longer-term value of demand reduction — which reduces the incentive for end-users to undertake capital expenditure to enable demand-response;
- the uncertainty that a particular customer will remain with a retailer over the longer term — which reduces the incentive for a retailer acting as a demand side aggregator to undertake capital expenditure to enable demand response;
- the fact that third-party aggregators have no way to participate in non-scheduled demand response;
- various aspects of network regulation and pricing that fail to capitalise on the potential for DNSPs to act as demand side aggregators; and
- the greater certainty and (generally) ready availability of financial instruments to provide acceptable levels of risk management for retailers.

The amount of demand-response in the NEM is still relatively small although various steps have been taken in the last three years to test the level of price responsive demand, establish demand aggregators and examine ways of modifying the codes, procedures, regulations and commercial disincentives that potentially limit its utilization.

The way non-scheduled demand side response typically works in the NEM is through a customer load having a contract with an electricity retailer or with a distribution company.

7.1.1. Retail Company Demand Side Response Contract

A retailer (i.e. buyer) contracts with a customer who is willing to voluntarily reduce consumption of electricity (i.e. shed load) at times of high prices (i.e. seller). For this, the retailer typically offers to share the money saved by the retailer by reducing its exposure to pool prices on the contracted volume. In some cases, the retailer may offer a guaranteed minimum price for the avoided load (in $/MWh terms) in order to provide cashflow certainty to the end-user. The retailer may alternatively offer the customer a discounted energy tariff.

The result is that by shedding load the retailer's portfolio is less exposed to high prices, and the savings are shared in some way with the customer.

Customers in these arrangements often impose certain restrictions, including on:

a) the notice period required for load shedding;

b) who controls the load shedding (the customer of the retailer);

c) when load shedding can occur (i.e. time of day, day of the week, number of consecutive days, season);

d) how long the load reduction can last;

e) the maximum number of times per week, season or year the customer will undertake to deliver the load reduction; and

f) the conditions under which the customer should be excused from the obligation to deliver the load reduction.

7.1.2. Distribution Company Demand Side Response Contract

Alternatively, a distribution company could contract with customers and aggregate and on-sell those load reductions to the retailers of the customers involved. Distributors have not done so because they:

a) generally do not have direct relationships with customers;

b) do not see marketing and demand side issues as areas of their core expertise or business focus;

c) would probably have to undertake most of the costs associated with such activities on a speculative basis, as they would not be likely to qualify as network-related costs; and

d) do not have load control technologies that are easily addressable at the individual customer level, which would be required to in order to allow different retailers to request load reductions at different times.

There has been some interest shown by regulators and DNSPs in demand side actions to defer capital investment to augment the network in areas where peak demand growth is high.[10] However, in such cases, the applicable cost-effectiveness test for demand response has been the deferral value of the capital investment. In the majority of cases, this benefit on its own will not fund sufficient demand management take-up to achieve the desired deferral of network capital augmentation costs.[11] The addition of the energy market benefit would make these undertakings cost-effective in many more cases, thereby providing benefits to the distribution tariff payers, individual customers, the energy market, and even customers on standard tariff arrangements.[12]

7.1.3. Demand Side Contracts' Characteristics, Risks and Role in Risk Management

The following discussion focuses on retailer (or load aggregator) contracts with price responsive loads that are used for financial risk management, as they are seen as the demand-response aggregation approaches that would most readily benefit from the development of a short-term forward market arrangement.

For the retailer, a demand side contract is like a limited call option.[13] For the seller, it functions as a limited put option. Both parties, however, need to optimise the use of the option under uncertain future conditions. The key uncertainties are as follows:

- the number of times the option will have any appreciable value is entirely variable in any given year;
- the actual value of the option is highly variable from event to event; and

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10 See, for example, Office of Regulator General (2001) 'Determination of Somerton Power Station for AGL', Essential Services Commission, Melbourne.

ESC (2004b) *Electricity Industry Guideline No. 15 - Connection of Embedded Generation (Issue 1),* Essential Services Commission, Melbourne.

11 A detailed examination of this has been undertaken by CRA for the Essential Services Commission of South Australia. See ESCOSA (2004) *Final Consultation Draft: Review of Chapter 3 of the Electricity Distribution Code: Supplementary Determination*, ESCOSA, Adelaide, August.

12 This latter effect would be a by-product of reduced price volatility in the pool, which would translate into lower price in the forward contract market on which calculation of the standard tariff is often based.

13 An option gives the purchaser the right, but not the obligation, to buy or sell the underlying asset (in this case electricity) at a certain price (the *strike price*) on or before a certain date (the *expiry date* or *maturity*). For this right, the purchaser (or holder) pays the seller a *premium*. The seller (or writer) has the obligation to buy or sell at the strike price, should the purchaser exercise his right. A *call* option gives the holder the right to buy the underlying asset, a *put* option the right to sell. An option contract running over a period of time may have a limited number of times when the call or put option can be exercised.

- there is likely to be a limit on the number of times the option can be exercised in any given year[14].

Their joint problem is similar to the problem faced by a hydro generator or fuel-constrained gas plant that must choose when best to use its fuel to maximise its value, while also gambling that prices sufficient to justify their commitment costs will be sustained over the period in which they generate.

In addition to the uncertainties discussed above several other risks confront those selling demand side response and those buying it as a form of hedging instrument in the NEM.

- ***Sellers*** face revenue uncertainty because day-ahead or hour-ahead forecast high prices might not eventuate in real-time. This is due to NEM's lack of financial obligation on accepted bids and offers prior to real-time dispatch. The worst case for a seller occurs when, based on high pre-dispatch prices it commits to voluntary load shedding, and disrupts its principal economic activity (e.g. manufacturing production), and then real-time prices are low. The net result in this case is likely to be that (a) no pool benefits accrue to the retailer, and therefore there can be no benefit sharing with the seller; and (b) the seller's costs of production disruption are in no way compensated.

  Even when the outcome is not this dire, the fact that the value of load reductions are not known with certainty until very close to the time of dispatch limits the amount of demand-response that can be deployed. In many cases the commitment to switch off needs to be taken ahead of time — from several hours to a day or more. Only in those cases where this decision is entirely immaterial to the operations of the seller will such a decision be made without consideration of the revenue to be received, and this is the vast minority of cases.

- ***Buyers*** also face a version of this risk. To enlist sellers they often promise a minimum price for a call. They do this to ensure that they can get the demand response when their risk position requires it. This can result in buyers paying out more than the load reduction actually turns out to be worth. This can happen when their risk position requires them to call for demand-response in advance of an event and the predicted pool price does not materialise (or drops due to their exercise). To cover this risk, most retailers offer arbitrage revenue splits close to 50/50 to their customers. This gives the retailer revenue to cover occasions when the price does not eventuate and they have to make guaranteed minimum payments. It also makes retailers cautious about calling the demand response, and, because it lowers the value to the seller, results in a lower level of demand response being offered into the market in the first place.

14 Most, but not all, sellers are likely to limit the number of times they are prepared to have their load interrupted in order to keep operational disruptions within manageable bounds.

On the other hand, buyers also face a volume risk because demand side sellers might reject the call to shed load. The retailer can offset this somewhat by contracting with a larger volume of demand response over a diversified number of sellers so that it can be reasonably sure that it will get a set volume of response when it calls the options. And, finally, calling a contract at a time when high prices are not sustained can reduce the number of call options left on the contract, thereby potentially exposing the retailer to high prices because it can no longer call on the option in future when high prices prevail.

Together, these risks reduce the value of demand side contracts to both parties and the appetite of both to enter into them. The main factor reducing the perceived value of both parties is uncertainty around the pool revenue savings, and the fact there is no guaranteed income stream to underwrite the contract. Under such conditions, retailers often find it cheaper and/or easier to buy cap contracts, or other insurance contracts to manage financial risk – for example look-back insurance[15] – rather than attempting to manage a demand side portfolio. Demand side initiatives then tend to be limited to those resources that can respond quickly or pose no material inconvenience to the seller's operations, and require minimal or no capital expenditure.

7.2. Likely Effects of Multi-Settlement on Demand Side Response in NEM

A short-term forward market will not overcome all of the impediments to demand response that have been discussed here and in the various market reviews carried out over the past few years; including, most recently, by the Ministerial Council on Energy's User-Participation Working Group.

The suggestions here deal with how to use demand side, but clearly cannot address issues such as metering or facilitate the operation of load aggregators.

15 Look-back insurance allows the purchaser at the end of a year to nominate a set number of time intervals during the year when it wishes a cap contract to operate. For example, say there were thirty-five instances in a year where spot prices were above $1000/MWh and the look-back cap can be exercised in five intervals; then, the holder of the look-back will choose to exercise the option in the five intervals where the difference payments from the cap contract are most valuable in reducing its exposure to pool prices. The up-front premium required to secure a look-back contract is less than that required for a cap contract operating over a larger number of time intervals in the year (for example, the 43% of annual hours in a 'peak' contract) because the probability of a claim is lower.

However, the creation of a multi-settlement market, with its binding financial obligations would provide increased certainty to the income stream from demand response of the type that cannot achieve that now, thereby allowing its costs and benefits to be better predicted. Loads would be more willing to commit in advance of being dispatched, knowing that if their bid is accepted they will be paid the day-ahead clearing price. Similarly, retailers will be better able to manage decisions on when to call on demand side response and how to optimise the portfolio value it can provide them.

8. INITIAL ACCC REJECTION OF NEC CLAUSE 3.10

The National Electricity Code originally contained clause 3.10, which required the National Electricity Market Management Company (NEMMCO) to facilitate the establishment of a short-term forward market.

The proposed short-term forward market had two purposes: first, to facilitate price discovery and participant risk management; and second, to assist the market in efficiently balancing expected supply and demand across the NEM.

However, when the Code was submitted to the ACCC for approval, the Commission authorised the Code on condition that clause 3.10 be removed.

The ACCC removed clause 3.10 because of two concerns it had:

- That if NEMMCO ran the short-term market, it would crowd out other potential service providers (e.g. the Sydney Futures Exchange); and
- That NEMMCO might have conflicts of interest if it both ran the short-term forward market and took a position in it.[16]

In addition, we note that:

- To date, no organisation in Australia has attempted to establish an exchange trading day-ahead short-term electricity contracts;
- The Sydney Futures Exchange (SFE) tends to trade longer-dated futures contracts, which are not so reliant on information close to dispatch;
- Unless NEMMCO as the exchange operator were allowed to take a position in a short-term forward market, it would be neutral and this neutrality could be imposed via the Code or by the Australian Securities and Investments Commission (ASIC);
- NEMMCO's role is strictly prescribed in the Code and concerns over its potential liability have tended to make it highly risk averse; and
- After five years of market operation, are there any instances where NEMMCO has purposely operated the market in ways that are inimical to market efficiency but in some way beneficial to itself?

16 ACCC 1997, *Applications for Authorisation: National Electricity Code, Authorisation nos. A40074, A40075, A40076*, Australian Competition and Consumer Commission, Canberra, 10 December, pp.83–86.

In summary, the concern about NEMMCO crowding out other exchanges does not appear to have materialised. Further, concerns about NEMMCO's potential conflicts of interest in operating an exchange could be managed by a market design that ensures NEMMCO remains neutral**.**

9. DESIGN AND IMPLEMENTATION

The preceding sections have described how a STFM can affect a number of market characteristics and underscores the importance of designing with a clear view of the objective to be achieved. A STFM can, we believe, incrementally improve the opportunity for demand side participation but a STFM should be seen as part of a larger response addressing network and retail matters as well. The proposal contained here is for a simple instrument that has much in common with a facilitated broker arrangement and thus differs considerably from earlier more comprehensive designs. We are suggesting this, as there is no strong appetite expressed by participants for a more comprehensive instrument. The earlier STFM proposal allowed for inter-regional contracting that is now covered in part by the Settlement Residue process. While it would be possible to update proposals based on the philosophy underpinning the initial design of a STFM, our view is that a complicated approach would be viewed as something of an over-kill. Therefore, the proposal here is for a very simple supplement for bilateral contracting at each reference node. No facility would be offered to accommodate inter-regional transactions over and above the existing mechanisms in the market. There would be a quantum leap in the complexity, establishment and transactions costs if the mechanism were to be extended to inter-regional transactions.

Market Operator

Although it is possible that the STFM might be operated independently of NEMMCO, we are proposing that NEMMCO operate the STFM because NEMMCO already has a relationship with market participants and has the facilities to accept bids and offers, match them, and the settle them. The existence of these facilities means the transactions costs of a NEMMCO-run STFM are likely to be lower than those associated with either setting up an independent exchange, or operating the STFM via the ASX or SFE.

Other potential benefits of having NEMMCO run the STFM include:

- A single inter-face for users operating in the day-ahead and real-time markets; and

- Lower prudential costs for some market participants who can off-set their real-time prudential requirements with revenue from the day-ahead settlement process. The degree to which this occurs will depend on the level and cost of meeting existing prudential requirements, and the degree to which a participant's day-ahead settlement covers its likely real-time settlement obligations. In the case of generators, who currently do not have to lodge prudential guarantees because they are generally expected to net recipients from the pool, participation in the day-ahead market might result in a greater prudential obligation if the generator were buying contracts in the STFM. Regardless, whenever a generator incurs a contract exposure (i.e. generator is a purchaser rather than seller), it will move further towards being a credit risk and only through NEMMCO does it have the opportunity to net out contract position against its pool revenue. If reduction of prudential exposure were a significant issue in the market, one would expect to see a far more aggressive interest in the Code's existing provisions for settlement reallocation transactions (NEC Clause 3.15.11) — this has not been the case.

Some arguments against having NEMMCO operate the STFM are the:

- costs of operating the voluntary market will be socialised across all NEM market participants, rather than being borne by the STFM's participants; and

- range of instruments traded in an STFM administered by NEMMCO will be limited.

However, with regards to the first point above, it is arguable whether the cost of establishing multi-settlement and a voluntary STFM would add significantly to existing costs borne by market participants. All market participants have the potential to make use of the short-term market — unlike the FCAS markets or FRC — so it could be argued that is equitable that all contribute to its establishment costs. Although we note that a brokerage fee could be used to isolate the operational costs of the STFM to users of the market.

In relation to the charge that a NEMMCO-run STFM would have a limited range of standard contracts, the same can be said of any clearing-house exchange. The real issue is whether the creation of the STFM with its standard instruments would facilitate the development of other instruments outside the exchange. Our proposal is that STFM instruments would be very simple. The simplicity would allow rapid introduction of alternatives.

Main Features of STFM

The main features of the STFM would be:

- Contracts would be for simple financial instruments;

- Voluntary day-ahead market settled prior to dispatch combined with the NEM's existing real-time dispatch and settlement process;

- The day ahead market could be used to fine-tune contract positions, and would supplement — not supplant — longer-term bilateral contracts or longer-term exchange traded electricity contracts offered by the ASX or SFE. That is, the trading on the day-ahead market would most likely be in relatively small volumes, with the bulk of market participants' positions covered well ahead of time by long-term contracts;

- Buyers and sellers would submit 'blind' day-ahead bids and offers in a standard format for either a 24 hour period or nominated agreed peak periods. The process is 'blind' in the sense that no information on the likely prices of the day-ahead market are published before the market operator publishes the binding day-ahead dispatch prices that are used for settling participants dispatch in the day-ahead market;

- It would be a matter for the participants to ensure that if accepted these day-ahead bids and offers were commercially and physically rational for them;

- As the instrument would be referenced to the reference node, transmission risk would be the same as if a short-term back-to-back bilateral trade had been written;

- The day-ahead market would close two hours after the first pre-dispatch run was published by NEMMCO for the following day. This will allow participants to assess the next day position and finalise price and volume bids and offers;

- NEMMCO would publish the results of the day-ahead STFM to contracting parties only within three hours of the closing time for day-ahead bids and offers;

- For the purposes of prudential obligations NEMMCO would treat obligations under the contracts in the same way as spot transactions but would assess the net obligation of participants activities under spot, STFM, and settlement reallocation transactions; and

- Real-time dispatch would use the NEM's existing pre-dispatch process, with settlements.

10. SUMMARY AND CONCLUSIONS

The introduction of a short-term forward market has the potential to improve a number of characteristics of the NEM, but primarily those relating to:

- Demand side participation. There is an interesting tension between retailers seeking to encourage consumers to be more aware of energy consumption in general and being able to manage exposure to prices. Retailers to a large degree are able to simply pass on the costs of supply side management in tariffs. Regulatory authorities have little real world alternative but to endorse this when considering what actions a prudent retailer might take to protect against high and volatile prices when they review tariffs. If a mechanism emerged that made it more viable for demand side to emerge there would be another "string to the bow" of those regulatory authorities to provide a commercial reason for retailers to pursue demand side with more vigour;

- Facilitation of peak plant participation by offering plant requiring advance notice or expenditure to arrange fuel or labour (e.g. gas nominations);

- Enhanced (but still limited) monitoring of short-term reliability; and

- Transparency of contracting opportunities. Notwithstanding that in reality, as a result of contracting, market participants are effectively never exposed to the full volatility of high spot prices, the political implications of price volatility can be severe. In practice the extreme prices seen in the NEM are not forecast in advance but are the result of on-the-day events. A centrally run short-term market would provide a public reference price for contract prices. This might be complemented by information from Over-the-Counter (OTC), broker and exchange prices for the longer-term contracts.

Less significant improvements are likely in relation to advance planning of commitment of generators.

However, the degree to which these improvements will eventuate is highly dependant on participation and this is a behavioural issue. We are aware that previous attempts by SFE and ASX to offer additional contracting opportunities have been at best marginally successful. A short-term forward market would be targeting a different part of the contracting arena but success cannot be assured.

We suggest that a "market game" that modelled possible short-term forward market designs aimed at complimenting the existing market would provide valuable information about attitude and design detail.

DEFINITIONS

ACCC: Australian Competition and Consumer Commission.

Adequacy — The ability of the electric system to supply the aggregate electrical demand and energy requirements of the customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.

Aggregators **—** Commercial entities that bring together collections of customer loads or generators to take advantage of economies of scale and diversity among the loads or generators being combined.

Ancillary Services are services that provide for power system security, quality of supply and enhanced gains from spot market trading that would not be voluntarily provided by market participants on the basis of energy prices alone. There are three broad classes of ancillary services: Frequency Control Ancillary Services (FCAS), Network Control Ancillary Services (NCAS), and System Restart Ancillary Services (SRAS).

ASIC: Australian Securities and Investments Commission

ASX: Australian Stock Exchange

Bulk-Power System — The portion of an electric system comprising the generation resources, system control, and high-voltage transmission system.

Co-optimisation involves solving the mathematical problem of finding the levels of dispatch of energy and ancillary services, which together give the least-cost solution. Dispatch arrangements that do not use co-optimisation typically set the level of ancillary services first and then determine energy dispatch.

Demand-Side Management — Programs that affect customer use of electricity, both the timing (sometimes referred to as load management) and the amount (sometimes referred to as energy efficiency).

Distributed Generation — A distributed generation system involves small amounts of generation located on a utility's distribution system for the purpose or meeting local (substation level) peak loads and/or displacing the need to build (or upgrade) local distribution lines.

Distribution System — The portion of an electric system that 'transports' electricity from the bulk-power system to retail customers, consisting primarily of low-voltage lines and transformers.

Embedded Generation — see *Distributed Generation***.**

Frequency **—** the rate, in cycles per second (or Hertz, Hz), at which voltage and current oscillate in electric power systems. The reference frequency in Australia's National Electricity Market is 50 Hz.

***Frequency Control Ancillary Services (FCAS)* —** A group of technical services that are provided to manage the frequency and time errors in the power system to within standards set by the NECA Reliability Panel.

Load — A consumer of electric energy; also the amount of power (sometimes called demand) consumed by a utility system, individual customer, or electric device.

Load Shedding — The process of deliberately removing (either manually or automatically) preselected customer demand from a power system. This process may be initiated in response to an abnormal power system condition so that the integrity of the system is maintained and to minimise the extent and duration of customer outages. *Voluntary load shedding* occurs when a customer elects to reduce its own load, or allow its supplier to curtail its load, in response to high prices or in accordance with a connection agreement.

Network Control Ancillary Services (NCAS): A group of technical services that are provided to support and enhance the secure power transfer capability of the network.

Operating Reserves: Frequency Control Ancillary Services.

Option: An option gives the purchaser the right, but not the obligation, to buy or sell the underlying asset (in this case electricity) at a certain price (the *strike price*) on or before a certain date (the *expiry date* or *maturity*). For this right, the purchaser (or holder) pays the seller a *premium*. The seller (or writer) has the obligation to buy or sell at the strike price, should the purchaser exercise his right. A *call* option gives the holder the right to buy the underlying asset, a *put* option the right to sell. An option contract running over a period of time may have a limited number of times when the call or put option can be exercised.

Security — The ability of the power system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements.

Reliability — The degree of performance of the elements of the bulk-power system that results in electricity being delivered to customers within accepted standards and in the amount desired. Reliability may be measured by the frequency, duration, and magnitude of adverse events on the electric supply. Electric system reliability can be addressed by considering two basic and functional aspects of the system — *adequacy* and *security*.

NEC: National Electricity Code.

NECA: National Electricity Code Administrator.

NEMMCO: National Electricity Market Management Company.

SFE: Sydney Futures Exchange.

***System* —** An interconnected combination of load, generation, transmission, and distribution.

***System Restart Ancillary Services (SRAS)* —** The technical service concerned with recovery from a partial or total power system failure (i.e. black-out).

Unit Commitment — The process of determining which generators should be operated each day to meet the daily demand of the system.

Voltage — The unit of measure of electric potential.

APPENDIX A: PJM AND NEW ENGLAND MARKETS

This appendix provides an overview of the design of the PJM and New England electricity markets in the USA and a description of their multi-settlement processes.

A.1 PJM Market — Key Components and Settlements

A.1.1 Day-ahead Energy Market

- Allows purchase & sale of energy at binding day-ahead prices.
- Schedule created using least-cost security constrained unit commitment & security-constrained economic dispatch programs.
- Hourly LMPs calculated using generation offers, demand bids & bilateral transaction schedules.
- Day-ahead congestion charges for bilateral transactions based on differences in LMPs between the transaction's *source* (i.e. network injection point) and *sink* (i.e. network off-take point).
- Incorporates reliability requirements and reserve obligations into analysis
- Demand may specify fixed quantity and location.
- Price sensitive demand may specify reservation price above which it wishes to be removed from day-ahead schedule.
- PJM Capacity resources must submit offers, if available, or may self schedule.
- Non-capacity resources may submit offers or may self schedule.
- Transactions may submit schedules into the day-ahead market.
- Transactions may specify max amount of congestion they are willing to pay.
- All day-ahead transactions must be associated with transmission service that is designated willing to pay congestion charges.
- Market participants may also specify increment offers and decrement bids.
- Generation offer must not exceed $1000/MWh.
- Can submit offer data up to seven days in future.

A.1.2 Real-time Energy Market

- Calculate hourly LMPs based on actual system operations security-constrained economic dispatch.
- LSEs pay real-time LMP for any demand that exceeds their day-ahead scheduled quantities.
- Generators receive prices for any generation that exceeds their day-ahead scheduled quantities.
- Transmission customers pay congestion charges for bilateral transaction quantity deviations from day-ahead schedules.

A.1.3 Load Response Market

- The ability of end-use retail customers to reduce their electric consumption in response to either price or system reliability events.
- When response achieved, the payment received for performance is based on wholesale market prices.
- Emergency load response program: enable participants that reduce load during emergency conditions to receive payment for those reductions.
- Economic Load Response Program: provides incentive to customers to enhance ability and opportunity for customers to reduce consumptions when prices are high.

Purpose of Load Response Program

- Provides a method that enables end users the opportunity to receive a revenue stream for reducing electricity consumption when wholesale prices are high, or the reliability of the wholesale electric grid is in jeopardy.

A.1.4 Settlements

- Day-ahead: Based on scheduled hourly quantities and day-ahead hourly prices.
- Day-ahead energy market settlement: Hourly net energy market position priced at day-ahead LMPs. Net position based on cleared increment and generation offers, decrement and demand bids, imports, exports, and bilateral energy transactions.
- Real-time: Based on actual hourly quantity deviations from day-ahead schedule hourly quantities priced at real-time LMPs.

- Balancing settlement of real-time energy market: hourly deviation between real-time & day-ahead net spot market energy positions priced at real-time LMPs. Real-time net energy position based on real-time generation, load, imports, exports, and bilateral energy transactions.

- Demand scheduled day-ahead: Pays day-ahead LMP for day-ahead MW scheduled, pays real-time LMP for actual MW above scheduled, paid real-time LMP for actual MW below scheduled.

- Generation scheduled day-ahead: Paid day-ahead LMP for day-ahead MW scheduled, paid real-time LMP for actual MW above scheduled, pays real-time LMP for actual MW below scheduled.

A.1.5 PJM Market Operations Timetable

12 pm: Closing of receiving of bids & offers for next day.

- Determines commitment profile that satisfies fixed demand, price sensitive demand bids, virtual bids & offers, and PJM operating reserve objectives.

- Minimises total production cost.

12 – 4 pm: Day-ahead market closed for evaluation by PJM

- 4pm: Day-ahead results posted and balancing market bid period opens.

4 – 6 pm: Re-bidding period

- 6pm: Reserve adequacy assessment (reliability focus, uses updated unit offers & availability, based on PJM load forecast, minimises start-up & cost to run units). Transmission security assessment (reliability focus, performed as necessary starting two days before operating day, based on PJM load forecast).

Throughout operating day

- PJM system operator continually re-evaluates security constrained dispatch and real-time offers and sends out individual generation schedule updates, as required.

A.2 ISO New England

A.2.1 Multi-Settlement

- ISO New England settlement process is used to determine the charges to be paid to or by a market participant to satisfy its financial obligations. The process measures the amount of energy purchased and sold through the energy market and arrives at each market participant's payment.

- ISO New England operates day-ahead and real-time markets for electricity.

- Day-ahead market produces financially binding schedules for the production and consumption of electricity one day before the operating day.

- The real-time market reconciles any difference between amounts of energy scheduled day-ahead and the real-time load, market participant re-offers, hourly self-schedules, self-curtailments and any changes in general, real-time system conditions.

A.2.2 The Day-Ahead Market

- Occurs day before the operating day.

- Generation, demand, external contracts, and increment and decrement bids that clear in the day-ahead market settle at prices determined by the day-ahead market.

- One day ahead of actual dispatch, participants submit supply offers and demand bids for energy. These bids are applied to each hour of the day and for each pricing location on the system. Also, increment offers and decrement bids can be submitted, indicating prices at which supply or demand are willing to increase or decrease their injection or withdrawal on the system.

- From these offers and bids, the ISO constructs aggregate supply and demand curves for each location. The intersection of these curves identifies the market-clearing price at each location for every hour. Supply offers below and demand bids above the identified price are scheduled. Offers and bids that clear are entered into a pricing software system along with binding transmission constraints to produce the location marginal prices for all locations.

- The quantities and prices that clear are financially, not physically, binding. Generators and offers schedule in the day-ahead settlement are paid the day-ahead LMP for the megawatts (MWs) accepted. Scheduled suppliers must produce the committed quantity during real-time or buy power from the real-time marketplace to replace what was not produced.

- Wholesale buyers of electricity and virtual demand whose bids to buy clear pay for and lock in their right to consume the cleared quantity at the day-ahead LMP. Electricity use in real-time that exceeds the day-ahead purchase is paid for at the real-time LMP.

A.2.3 The Real-Time Market

- Spot market for energy.

- A number of factors can change the day-ahead market schedule, including unforeseen generator or transmission outages, transmission constraints or changes from the expected demand. The real-time market addresses these deviations.

- Day-ahead LMPs can differ from real-time LMPs when demand bids from the day ahead are not identical to actual system demand. For generators, the spot market provides additional opportunities to offer supply into the market to help address these variations. Those scheduled in the day-ahead market that fall short of their commitment may secure additional energy from the real-time market to cover that loss. Additionally, generator offers that did not clear in the day-ahead market are able to submit bids into the real-time market through a re-offer period.

- After the day-ahead market clears and its results are published, a two-hour re-offer period commences beginning at 4pm the day before the operating day. At this time, only offers to supply that did not clear in the day ahead market may be re-offered for the real-time market. Demand bids, increment offers and decrement bids may not be re-offered.

- When the re-offer period closes, ISO New England performs a reliability assessment. The cleared day-ahead offers from generators and bids from loads are compared with the ISO's forecast of energy, reserves and load capability, or regulation. The ISO will, if necessary, select additional resources, based upon re-offers, that can serve the projected need for energy and real-time ancillary services. This is called the "Current Operating Plan" and is adjusted throughout the day should system conditions warrant.

- Generators can also deviate from the day-ahead clearing schedule by submitting a request to "come on" in any hour not cleared in the day ahead through a self-commitment and self-scheduled submittal, or ask to "stay off" in any hour even if they have already cleared day ahead.

- Participants will continuously throughout the day be allowed to offer or request imports and exports of electricity from neighbouring control areas with at least one hour's notice. In real-time, ISO New England will issue "dispatch rates" and dispatch targets. There are five-minute price and MW signals based on the aggregate offers of generators, which will produce the required energy production.

- Real-time prices are based on actual power system output (ex-post). This methodology enforces market discipline because it permits generators to set prices only if they have followed dispatch instruction.

- Differences from the day-ahead quantities cleared are settled at the real-time LMP. Those who were committed to produce in the day-ahead are compensated at (or pay) the real-time LMP for megawatts over (or under) produced in relation to the cleared amount. Those who paid for day-ahead megawatts are paid (or pay) the real-time LMP for megawatts under (or over) consumed in real-time.

- The same software calculates both day-ahead and real-time LMPs.

A.2.4 ISO New England Market Operations Timetable

12 pm: Day-ahead market closes. (1st unit commitment)

- Demand: demand bids, decrement bids, and exports

- Supply: generator offers, incremental offers, and imports

- Establishes day-ahead LMPs and financially binding positions

4pm – 6pm: Re Offer Period (2nd unit commitment)

- Demand based on ISO New England load forecast

- Supply not previously committed eligible to re-offer and self schedule

- Settled in real-time market

During the trading day: Real-Time Market

The New England ISO:

- Computes real-time LMP price signals and unit level dispatch every five minutes;

- Physically balances the market using real-time bids and offers for energy and ancillary services; and

- Maintains adequate operating reserves.