The Status of the Australian Electricity Market: Market Structures and Trading Contracts

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SUMMARY

This paper initially examines the Hilmer Report recommendations insofar as they are applicable to the structure of the electricity industry, and the steps that the Council of Australian Governments has recommended be undertaken in order to implement the reforms recommended by the Hilmer Report.

The paper then briefly outlines the structural changes to the electricity industry that have occurred to date in each of the Australian States, reflecting the progress towards adoption of the Hilmer Report recommendations.

The balance of the paper describes the trading structure of the national electricity market, which is proposed to commence in Australia on 1 October 1996, and discusses the various electricity trading contracts that are likely to be available on and off the national market.

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BACKGROUND TO THE MICROECONOMIC REFORM PROCESS

The Hilmer Report

The microeconomic reform process that is driving structural change in the Australian electricity industry is largely based upon the recommendations of the report of the Committee of Inquiry into National Competition Policy, commissioned by the Australian government in 1992 (the Hilmer Report).

The Hilmer Report recommended significant structural reform of public monopolies in Australia, including the Australian electricity industry (which had to that time been operated as a series of public monopolies in each State and Territory). Previous government inquiries had established that there was considerable scope for increased efficiency and competition in the Australian electricity industries.[1] The Hilmer Report pointed out that the introduction of effective competition into markets traditionally supplied by public monopolies will often require more than the removal of regulatory restrictions on competition. The excess market power held by such public monopolies is likely to impede the introduction of effective competition, and therefore reform would require dismantling of the monopolies in addition to the removal of regulatory restrictions on competition.

The Hilmer Report identified three separate types of structural reform that may be required in any particular industry:

1. the *separation of regulatory and commercial functions*, which could create a potential conflict of interest in a competitive market;

1. Industries Assistance Commission Report 1989, Industry Commission Report 1991.

2. the *separation of natural monopoly elements* from potentially competitive activities, because control over access to a natural monopoly might be used to stifle or prevent competition in the market, or if not exercised in that way the potential to do so may deter new entrants into the market; and
3. the *separation of potentially competitive activities* by splitting or dismantling entities with substantial market power into a number of distinct competitive entities capable of competing with each other.

Translating the Hilmer Report to the electricity industry

For the electricity industry, these structural reforms recommended by the Hilmer Report could be translated into:
1. placing regulatory functions in a national electricity industry regulator that does not carry on trading functions, leaving the trading functions of generation and distribution to be run by separate government or privately-owned bodies;
2. identification and separation of the natural monopolies of the high voltage transmission networks and the low-voltage distribution networks, developing systems for open access to those networks; and
3. splitting large government-owned generation enterprises into several smaller competitive enterprises, and consolidating small government-owned regional distribution enterprises into a number of larger enterprises capable of competing with each other.

Council of Australian Governments

The Australian federal system of government vests power in the federal government only in a limited range of areas, leaving the balance of responsibility to State governments. The Hilmer Report recognised that this federal system, which decentralises much industry regulation and government intervention in industry to the State and Territory level, presented an obstacle to the reform of national industries such as electricity.

The recognition of the need for micro-economic reform to support higher economic and employment growth, and the recognition of the obstacles presented by the diversity or government regulation and intervention, had in 1991 prompted the formation of the Council of Australian Governments (COAG). COAG is an intergovernmental forum comprising the Prime Minister, Premiers and Chief Ministers of each of the States and Territory governments, and the president of the Local Government Association. COAG met twice in 1993, and at its third meeting in February 1994 enunciated these objectives:[2]

- increased co-operation among all spheres of government in the national interest (presumably as opposed to interest of the respective States and Territories);

2. Communique of the Council of Australian Governments, Hobart, 25 February 1994, p 1.

- assistance in bringing about a more competitive and integrated national market;
- more efficient and effective arrangements for the delivery of services (in areas of shared responsibilities);
- a broad micro–economic reform agenda covering a number of industries; and
- adoption of the Hilmer Report, insofar as the electricity industry is concerned.

Structural changes being undertaken pursuant to COAG

The structural changes that COAG has proposed be undertaken towards micro–economic reform of the Australian electricity industry include:[3]

- separation of the various functions of generation, transmission, distribution, and regulation (both technical and safety);
- development of a single national market in electricity;
- development of a market culture within the government trading enterprises;
- obtaining experience in market instruments and contracts;
- developing competitive interstate trade;
- working towards an agreed restructuring of the Snowy Mountains hydro scheme, which is currently operated by the Commonwealth, Victorian and New South Wales governments;
- seeking a uniform approach to network pricing and regulation, including common asset valuation methodologies and rates of return, and cost-reflective or transparent pricing for grid and network;
- interjurisdictional merit order commitment and dispatch;
- interstate sourcing of generation (where cost-effective);
- open access to natural monopolies such as transmission and distribution networks; and
- implementation of transitional arrangements such as vesting contracts and separate state markets, as a precursor to the national market.

In 1991 COAG established the National Grid Management Council (NGMC) to oversee the development of the national electricity market and the open access regimes.

Government trading enterprises

Until recently, virtually all of the functions of the Australian electricity industry (other than the supply of materials and equipment) have been undertaken by government-owned trading enterprises and other government instrumentalities. The Hilmer Report recommended that:

1. a mechanism to deal with "competitive neutrality" as between government businesses and other businesses should form part of Australian national competition policy;

3. Ibid, pp 7-10.

2. all State governments should agree to abide by principles that are aimed at achieving competitive neutrality, and that in the case of government monopolies such competitive neutrality should be achieved within one year of the introduction of competition;
3. where there is a provision of services directly to the public, there should be a presumption that competitive neutrality is achieved through "corporatisation" of the government trading enterprise;
4. where the business of the government agency is the provision of services to other government agencies, competitive neutrality may be achieved through corporatisation or the application of effective pricing directions;
5. a National Competition Council should assist governments to develop and refine these principles; and
6. the Australian Competition and Consumer Commission should report allegations of non-compliance with agreed principles to the relevant State government and the National Competition Council.

Characteristics of reformed enterprises

Reform of the government trading enterprises to ensure competitive neutrality so that the government-ownership is neither an advantage nor a disadvantage to competition with other public or private entities in the industry has tended to include these factors:

1. clarity of objectives, so that the management of the enterprise understands its role and goals;
2. management autonomy and authority, so that the enterprise may trade within a defined scope and objectives without undue political interference;
3. accountability for performance, measured against the clearly defined objectives;
4. payment of tax equivalents so that the government trading enterprise does not enjoy any financial advantage against private sector participants that are subject to taxation;
5. payment of local government charges that would be levied against a privately-owned enterprise, or payment of an equivalent amount where it is be beyond the legislative competence of a local government to levy the charge against another government enterprise;
6. no government guarantee of its debt or other obligations, unless that guarantee is provided explicitly and in consideration of a market-equivalent fee paid by the enterprise to the government providing the guarantee;
7. dividend payments according to dividend policies that would be applied to private sector participants in the same industry;
8. a board of directors, with directors' duties equivalent to those imposed upon directors of private sector corporations;
9. removal of immunity from other legislation to which other

participants might be subjected (such as the *Trade Practices Act*), and the imposition of equivalent obligations to those imposed upon other enterprises (such as applicable provisions of the Corporations Law); and

10. recognition of community service obligations, so that where the government enterprise is obliged by its political masters to act in a manner which a private enterprise might not be so required, the obligation and its cost is transparent.

THE STATE MARKETS

Western Australia

The industry and population centres of Western Australia are so distant from the balance of Australia that physical integration of Western Australia's electricity markets with those of the other States and Territories of Australia is likely to be geographically inhibited for many years. Structural change in the energy markets of Western Australia is therefore less driven by the timetable for implementation of the national electricity market than it is in other States. However, a number of structural reforms have occurred or are proposed in Western Australia towards adoption of the recommendations of the Hilmer Report, including:

- the State Electricity Commission of Western Australia ("SECWA") has been split into two entities: Western Power and Alinta Gas, to promote competition between the two energy sources;
- the gas industry has been deregulated by disaggregation of the North-West shelf gas contracts;
- an open access regime for the Dampier/Bunbury gas pipeline is being implemented; and
- there is a proposed timetable for progressive open access to electricity transmission and distribution systems from 1 July 1997 (from 66kv lines with average load exceeding 10MW at a single point) through to 1 July 1999 (loads exceeding 5MW).

Significantly, vertical disaggregation of electricity generation from distribution, and separation of monopoly electricity transmission systems from other functions, has not yet occurred in Western Australia.

Queensland

In Queensland a degree of vertical disaggregation has occurred. Generation has been vested in the government-owned corporation Austa Electric. Transmission and system control has been vested in the government-owned Queensland Transmission and Supply Corporation (QTSC). Distribution and retailing is conducted by seven corporatised regional monopolies, each of which is a subsidiary of QTSC.

Queensland's physical participation in the national electricity market depends upon the development of interconnections with the other States, but there is now no timetable for that process. In March 1996 the recently–elected Queensland government announced the cancellation of the 500MW "Eastlink" interconnector, which had been proposed to connect the New South Wales transmission grid with that of the QTSC.

The Eastlink interconnector would have permitted generators in New South Wales to supply the increased loads in the growing population centres in south east Queensland, however Eastlink had been criticised from a number of quarters. Residents in the areas through which the Eastlink interconnector had been proposed to pass criticised it for the possible environmental consequences flowing from its installation as an overhead transmission line. An Australian Senate Commission of Inquiry into Eastlink had concluded that the installation of the line would only encourage increased reliance upon coal-fired generation at a time when the government should be seeking alternative sources of energy and methods of encouraging a reduction in electricity consumption.

In announcing the cancellation of Eastlink on 18 March 1996, the Queensland Premier Mr. Borbidge declared that:

> "the [Queensland] government has concluded that there is a need for greater reliance and reliability within the Queensland electricity system ... and interconnection with the southern states is not a priority matter."[4]

The Queensland Treasurer commented on the consequences for the national electricity market:

> "Queensland's withdrawal from the Eastlink project did not mean that the State would not join the national electricity market at some future date. [However] there are a number of conditions that have to be met before Queensland would join the national electricity market."[5]

It was subsequently reported in the press that:

> "Queensland has now backed away from plans to seek an exemption for the state's power industry under the Hilmer national competition policy reforms. The state will look at other ways of connecting to the grid."[6]

The cancellation of Eastlink, and the consequent unavailability of electricity from New South Wales, left a significant shortage of capacity in Queensland. On 9 April 1996 the Queensland Minister for Energy, Mr. Gilmour, described the need for new generating plant in Queensland as "critical".[7] The QTSC has since called for expressions of interest for proposals to meet Queensland's energy needs for the period 1998 to 2000,

4. Press release from the office of the Queensland Premier, 18 March 1996.
5. Press release from the office of the Queensland Treasurer, 21 March 1996.
6. Chanticleer column, *Australian Financial Review*, 11 April 1996.
7. Press release from the office of the Minister for Energy, 9 April 1996.

and from this process industry commentators are suggesting that it is likely that 500-600MW of new generating plant (probably gas-fired) will be commissioned in Queensland.

Without Eastlink or another interconnector, it is still possible that Queensland can participate in the national electricity market, although it would be regarded as a separate pricing region with a fully constrained interconnection to other regions. Whether Queensland participants will join the national electricity market from its inception on this basis is still unclear.

South Australia

South Australia intends to participate in the national electricity market from its inception, although the capacity of the interconnects to other regions is limited and the available flows likely to be constrained.

There has been some vertical disaggregation in South Australia, by the "ring-fencing" (business isolation) of the three business units (generation, transmission and distribution) of the government-owned electricity authority, ETSA, but as yet there has been no horizontal separation into competitive units.

On 21 May 1996 the New South Wales government announced a feasibility study for a $90 m interconnector between New South Wales and South Australia. Preliminary work indicated that the connection could be by a 275kV line running 300km from Mildura to a point 100km north of Adelaide. The link would permit the New South Wales generators to supply South Australia, especially in summer, when the New South Wales generators have spare capacity and South Australia's power consumption is at its peak.[8]

New South Wales

In New South Wales vertical disaggregation was achieved by creating the Transmission Authority of New South Wales ("TransGrid"), carving out the transmission and regulation functions from Pacific Power (which retained monopoly generation functions). Both of these entities are state-owned corporations.

In late 1995 Pacific Power was further disaggregated by transferring the majority of generation assets into two new State-owned generation corporations (Macquarie Generation and First State Power), leaving Pacific Power with the balance of the generation assets and New South Wales's entitlement to output of the Snowy Hydro scheme.

Distribution and retail functions had historically been performed by small regional monopolies controlled by local municipal and regional governments. In 1995 the New South Wales government sought to prepare these distributors for competition by aggregating them so that the assets and liabilities of 26 distributors were transferred into six regional State-

8. NSW Treasurer, M Egan, quoted in *The Australian*, 22 May 1996, p 4.

owned corporations (EnergyAustralia, Integral Energy, NorthPower, Advance, Southern and Broken Hill). Each distributor has a regional distribution monopoly but their customers will gradually be opened to retail competition.

From 1 March 1996 scheduling and dispatch of generators in New South Wales were controlled by TransGrid as the market and system operator of a compulsory New South Wales spot market in which the participants were the three generators, six distributors and ACTEW. The spot market sought to mirror insofar as possible the structure of the proposed national electricity on a single-region spot basis, including merit order and dispatch. The administered price was removed on 10 May 1996 and the New South Wales spot market has traded on an open bid basis since.

At the commencement of the New South Wales spot market the distributors and generators were "vested" with bilateral hedge contracts that effectively fixed the prices between them for quantities representing a substantial proportion of their average electricity generation/consumption, but still leaving a significant proportion to be traded on the variable spot market. The vested quantities automatically reduce over several years, to be replaced by negotiated bilateral contracts or spot market purchases.

At the time of writing, the New South Wales government was considering a number of options for the timetable for opening up distributors' local customers to competitive supply from other distributors and retailers. The timetable is anticipated to permit the largest consumers to be opened to competition from 1 October 1996, with consumers in descending magnitudes being deregulated through to 1999 or 2000.

Victoria

The restructuring in New South Wales largely followed the process that had already been undertaken in Victoria in 1994 and 1995, but Victoria has taken these further steps towards restructuring and competition in the electricity industry:

- the five Victorian distribution corporations (United Energy, Eastern Energy, Solaris, Powercor and Citipower) have since been privatised by sale to investors for prices totalling $8.6bn;
- Yallourn W power station has been privatised and Hazelwood power station is in the course of sale;
- the transmission function is in a separate corporation from system control and market operation (in New South Wales each is a function of TransGrid); and
- the regulation function has been separated into an Office of the Regulator-General (in New South Wales this is also a division of TransGrid).

Australian Capital Territory

All generation for the Australian Capital Territory comes from New

South Wales and the Snowy hydro scheme. The generation and distribution functions are handled by the government-owned Australian Capital Territory Electricity and Water Corporation (ACTEW). No significant structural reforms have occurred, but ACTEW has joined the New South Wales spot market and is anticipated to join the national electricity market.

Tasmania

In Tasmania electricity generation and distribution is handled by the state government-owned Hydro-Electricity Commission (HEC). Tasmania's geography as an island state may inhibit further reform or membership of the national electricity market until the proposed BassLink interconnect under Bass Strait is constructed.

Northern Territory

In the Northern Territory, the "tyranny of distance" is likely to prevent participation in the national electricity market. Because of the transmission losses involved, generation tends to be localised or regional rather than grid-based.

THE PROPOSED NATIONAL MARKETS

National market outline

The Australian national electricity market is planned to commence on 1 October 1996 involving the Australian Capital Territory, New South Wales, South Australia and Victoria (query Queensland's position - see above). The national electricity market is proposed to facilitate four principal types of transactions:

1. sale and purchase of physical flows of electricity to or from the grid through a compulsory *spot market*, at a spot price that has regard to the regional price, inter-region interconnectors, and transmission losses between and within regions;
2. short-term financial contracts in a *short term forward market* (STFM), which hedge against the resulting spot market price one or several days later;
3. *inter-regional hedge contracts* offered by an inter-regional trader (IRT) that permit a participant to hedge against the spot price in a region other than the region to which the participant is physically connected; and
4. *reallocation contracts* under which one market participant is billed by the spot market for a quantity of electricity for which another market participant would otherwise be billed.

Spot market - how it is to operate

The spot market of the national electricity market is intended to achieve a system for the sale and purchase of the physical flows of electricity within the market at a spot price equivalent to the marginal cost of the electricity. It is proposed that a government-owned corporation to be known as the National Electricity Market Management Corporation (NEMMCO) would operate the markets in this way:

1. NEMMCO would "purchase" electricity that market participants have contributed to the transmission grid or the grid of a distributor, by paying to them the spot price for electricity sent out through their meter.
2. NEMMCO would "sell" electricity to other market participants, by billing them at the spot price for electricity that is metered as having been drawn from the transmission grid or the grid of another distributor through a metered connection point, which is either:
   (a) a connection point between the transmission network and a distribution network operated by the relevant market participant (a "transmission connection point");
   (b) a connection point between a distribution network operated by the relevant market participant and another distribution network operated by another market participant (an "interdistributor connection point"); or
   (c) a connection point to which a consumer of electricity is connected in another market participant's distribution network, but for which the relevant market participant is responsible as the selected retailer for that consumer (an "independent connection point").

   The words "sale" and "purchase" are in inverted commas here because the sale and purchase does not necessarily involve the physical delivery of electricity to or from NEMMCO. Instead, the "sale" and "purchase" represent obligations to pay to or receive from NEMMCO an amount of money calculated by reference to a spot price multiplied by quantities of electricity metered as having physically passed through certain designated connection points, which may represent flows on distribution grids operated by market participants or transmission corporations rather than grids maintained or controlled by NEMMCO. The electrons do not necessarily flow in the same direction as the dollars.
3. For the purposes of calculating the amount to be billed to a market participant that operates a distribution network, NEMMCO deducts the amount of electricity passing through independent connection points within that distribution network (for which another market participant is the responsible retailer and which will be billed separately by NEMMCO), and adds back the amount of electricity contributed to the participant's distribution network by a market

participant generator (for which NEMMCO will pay the generator separately).

4. Each market participant will progressively notify to NEMMCO a series of rolling forecasts of projected generation availability (in the case of generators) and anticipated consumption loads (in the case of distributors and consumers), which will enable NEMMCO to publish rolling forecasts of Projected Anticipated System Adequacy ("PASA") and assist market participants to determine their market behaviour.
5. Each generator must for each day bid to NEMMCO a price (in bands of quantities) for its electricity available for dispatch that day, under a centralised bidding system. The generation units (and dispatchable loads) are then scheduled by NEMMCO for dispatch under a merit order stacking procedure, which schedules each unit in turn, from cheapest to most expensive bids, until dispatched generation reaches the system load requirements, so that (ignoring startup limitations) system demand is met by the cheapest available generation.
6. Generators who have already contracted their output under bilateral contracts with other consumers will typically enter a zero bid to ensure that they are dispatched for generation and can receive from the spot market the marginal spot price.
7. In each region the marginal cost of electricity at any time is the highest-priced generator's bid necessary to be scheduled to meet system load at that time, having regard to flows available from other regions via interconnectors (up to the capacity of the interconnector).
8. If all generators' bids are scheduled and the available capacity in a region is exceeded by the demand, the market and system operator will contact the distributors in that region and advise them to shed load. At this point the marginal spot price becomes the maximum set for the market (known as "VoLL" or "Value of Lost Load"). The maximum is likely to be set at $1,000 per MWh, moving to $10,000 per MWh after the market is established.
9. For each half-hour (a "trading interval") in every day the "regional reference price" is determined by NEMMCO for each region, being the weighted average of the marginal price for electricity in that region for that trading interval (the weighted average is required as the marginal price may move within the half-hour if the dispatch algorithm is run more than once in that half-hour due to fluctuations in load or supply within that half-hour).
10. Within each region there are "transmission connection points" to which distribution networks or generators are connected to the transmission network. Each of these transmission connection points has an associated "loss factor" (to represent the losses in transmission estimated to occur if electricity were sent from a notional centre node in the region (which has a loss factor of zero) to that transmission connection point. The spot price as at any transmission connection point is the regional reference price for the region multiplied by the

loss factor for the relevant transmission connection point.

11. Within each distribution network operated by a market participant that is a distributor there are "connection points" that represent a point of connection between the distribution network and:
    (a) a consumer of electricity that is itself a market participant, such as a large industrial customer ("participant connection point");
    (b) a consumer of electricity that is not a market participant, but has selected another retailer to be responsible as the selected retailer for that customer ("independent connection point");
    (c) a generator of electricity that is itself a market participant, but connected to the distributor's network rather than directly to the transmission network (also a "participant connection point");
    (d) another distribution network operated by another market participant (an "interdistributor connection point").
12. Each of these connection points is metered with a sophisticated meter that records the energy flows for each half hour, and the recorded data is transmitted to NEMMCO to enable calculation of trading payments.
13. The point of connection between the distribution network and a consumer of electricity that is not a market participant and has not selected another retailer, and for which the local distributor is therefore responsible as the selected or franchise retailer for that consumer, does not need to be a "connection point" with a market meter. If it does not have a meter, the local distributor will be responsible for paying the market because the electricity consumed will be a drain on the distributor's transmission connection points. If it does have a meter, the local distributor will be responsible as the responsible market participant for that connection point.
14. Similarly, a small embedded generator of electricity that is not a market participant because it is under the market threshold (perhaps a wind farm or solar cell), and supplies electricity to the distributor's network rather than directly to the transmission network, does not necessarily require a market connection point and meter - its output simply reduces the consumption of the distributor's network as measured at the distributor's transmission connection points. However, it would be expected that the generator and distributor would wish to have some detailed metering available so that the distributor may compensate the small embedded generator for its product.
15. Each of the connection points within a distribution network is notionally allocated to one of the transmission connection points for that distribution network. Each of the connection points is then allocated an "intra-regional loss factor", which is an estimate of the transmission losses within the distribution network from the allocated transmission connection point to the connection point itself.
16. The spot price for electricity at any connection point for any half-hour

trading interval is then a factor of the regional reference price for the region and the intra-regional loss factor for that connection point.

17. For each connection point there is a responsible market participant. Typically the responsible market participant will be the market participant that operates the local distribution network. However:
    (a) an embedded generator that is large enough to be a market participant will usually be the market participant responsible for its own connection point; and
    (b) where a customer has selected a retailer other than its local distributor, the market participant selected by the customer is responsible for that connection point.
18. The flows of electricity at each connection point may be metered as a positive or negative amount of electricity. A flow of electricity sent out through the meter towards the transmission network or the allocated transmission connection point is a positive flow (this would be the typical flow from a generator). A flow of electricity drawn from the transmission network or the allocated transmission connection point and through the meter into the participant's domain or own network is a negative amount of electricity (this would be typical of a participant that is drawing in or consuming electricity from the grid).
19. At each connection point the meter then produces a positive or negative energy amount for each trading interval. For each connection point to which other connection points have been allocated the energy amounts of the allocated connection points (excluding its own customer connection points) are added back in (that is, deducted where the flow is negative, added where the flow is positive) to derive the adjusted energy amount for that connection point.
20. The adjusted energy amount for each trading interval for each connection point is then multiplied by the spot price for that connection point for that trading interval to derive the trading amount for that connection point for that trading interval. The trading amount will be a positive dollar value where the connection point has sent out electricity, and a negative amount where the connection point has drawn in electricity.
21. If the trading amount for a connection point is negative, the market participant responsible for the connection point must pay the trading amount to NEMMCO (a "purchase" of electricity). If the trading amount for a connection point is positive, NEMMCO pays that trading amount to the responsible market participant (a "sale" of electricity by the market participant).
22. The trading amounts for each half-hour trading interval in a week are accumulated until the end of the week, at which time the net result of the positive and negative trading amounts are notified to the market participants. Market participants with a negative result are required to settle 20 business days after the close of the week by paying an amount to NEMMCO. Market participants with a positive result are

paid by NEMMCO from the proceeds of the payments made by the other market participants.

This description of the market operation is drawn from working drafts of the Market Rules section of the code regulating the market and may be subject to change before implementation.

Short–term forward market

It is proposed that NEMMCO would also operate a short term forward market ("STFM") in electricity by permitting market participants to bid to buy or sell quantities of electricity one, two or several days in advance of the actual trading interval. It is anticipated that this would enable generators with slow start-up capabilities to enter the market and fix a price to sell electricity in advance prior to start-up, so that they could then subsequently enter a zero bid in the spot market to be scheduled.

It is proposed that in the STFM NEMMCO would play a matching clearing counterparty role. When a buy and sell trade bid matched, NEMMCO would be the counterparty to the buy transaction with a market participant, and also the counterparty on the matching sale transaction with the market participant submitting the matching bid.

Transactions in the STFM are not physical buy or sell arrangements, but instead cash-settled forward or hedge transactions in respect of a single trading interval or region. The STFM transactions do not have any impact upon the scheduling of generators or obligations for payment for electricity in the spot market, but they give rise to trading payments that are intended to be settled on the same day as the spot market.

The STFM transactions would be closed out once the applicable trading interval has occurred, by reference to the spot price for that trading interval at the applicable regional reference node. Where the spot price for the trading interval is less than the strike price of the STFM transaction, the result is a positive trading amount for the STFM seller and a negative trading amount for the STFM buyer (NEMMCO pays to the STFM seller the difference between the strike price and the spot price, but NEMMCO collects a matching difference payment from the STFM buyer). The inverse of course also applies: where the spot price for the trading interval is more than the strike price of the STFM transaction, the result for the STFM seller is a negative trading amount (the STFM seller pays to NEMMCO the difference between the strike price and the spot price, but NEMMCO pays a matching difference payment to the STFM buyer).

As the STFM transactions are not physical transactions, market participants can participate in buy or sell transactions regardless of whether the market participant is usually a generator or consumer. In addition to assisting slow-start generators to self-commit by fixing a sale price in advance, the STFM may also permit:

- generators to fix a price to buy electricity, for example where the generator has a unit out of service and is concerned that the outage might cause the spot price to rise at a time when the generator cannot enter the market to receive that higher price and will have a liability to pay higher contracts for difference payments;

- retailers to enter the market and fix a price to buy electricity where their weather charts show weather that may lead to higher consumption than the retailer has already covered by long-term fixed contracts; and
- retailers to enter the market and fix a price for the sale of electricity for trading intervals where they are over-contracted and a sudden fall in the spot price may expose them to difference payments for quantities larger than the quantities that the retailers' customers consume.

Inter-regional trading

The Australian national electricity market is proposed to be composed of a number of regions, with transmission interconnectors between various regions. Theoretically, if the connections between regions had infinite capacity and there were no transmission losses, then the system marginal price in each region would be identical because any shortage of capacity in one region could be met by a flow of electricity from another region.

However, the theoretical world does not exist, and the interconnectors have physical limits upon the amount of electricity that can be supplied from one region to another. The physical constraints existing from time to time in the Australian electricity transmission systems will determine the shape of the regions, with constrained lines of transmission forming the interconnectors between regions. In the initial stages of the market the regions of the national market are likely to broadly reflect the State boundaries, because historically the transmission systems have been developed by State government authorities, with the emphasis on intra-State transmission rather than interstate transmission.

The constraints on interconnection give rise to differential prices between regions. Consider two regions, A and B, connected by an interconnector. If the generator bids in region B are cheaper than in region A, then to the extent that electricity can flow from B to A, the generators in region B can be scheduled to supply region A in preference to the more expensive generators in region A. However, once the interconnector from region B reaches its constraint limits, no further generators from region B can be relied upon to supply region A, and instead the more expensive generators in region A must be scheduled, giving rise to a higher marginal price in region A.

In this example, the generators in region B are paid the spot price for what they generate, calculated by reference to the regional reference price for region B. They are paid this price for all electricity they generate, including that which flowed over the interconnect to region A. The consumers in region A pay the spot price calculated by reference to the regional reference price for region A, which is higher than that for region B. This gives rise to a surplus in region A, because although all consumers in region A are paying spot price A, the cost of generation for part of the quantities consumed in region A is at the lower region B price. This surplus could possibly be used to reward the owner of the interconnector for providing capacity from an area of cheaper prices to an area of more expensive prices. The national market alternatively proposes to use the pool of inter-regional surpluses to enable NEMMCO to carry on business as an inter-regional trader ("IRT") offering inter-regional hedge transactions to market participants.

The inter-regional hedge transactions offered by the IRT would typically be one-way hedges under which a market participant paid to NEMMCO a premium to receive a difference payment if a specified region's spot price exceeded the spot price of another region. NEMMCO would be able to offer these hedges to the extent that the interconnector surpluses were available to NEMMCO should the prices of the regions diverge. The amounts payable to or by market participants under the inter-regional transactions with NEMMCO would constitute positive or negative "trading amounts" for the purposes of the national market settlement regime.

Reallocation

Under the national market design, a major consumer such as an electricity distributor will typically have an obligation to pay to the market the variable spot price for all electricity consumed by the distributor, whilst simultaneously having a bilateral contract with one or more generators, which provides for difference payments so that the net position of the distributor is a fixed price for the contracted quantity. At times of high spot prices, this can leave the distributor in a position where it must pay a large amount to the market at the variable spot price, and then collect a balancing large "contract for differences" payment from a generator. This exposes the distributor to the credit risk of the generator being able to make the large difference payments.

The process of reallocation (called "reassignment" in the original functional description of the national market) proposes the introduction of a transaction consisting of a set of matching quantities or amounts in the market that can be simultaneously credited to the account of one market participant (such as a distributor) and debited to the account of another market participant in respect of the same trading interval and at the same spot price. This reduces the amount that the credited participant must pay to NEMMCO for that trading interval, and reduces the amount that the debited participant is entitled to receive from NEMMCO for the same trading interval. The debited participant would accept the debit in consideration of the credited participant paying to the debited participant the full agreed price for the reallocated quantity by a settlement payment outside of the market, rather than just paying a difference payment.

The net position for NEMMCO is the same before and after the reallocation (because the credits and debits match), with the exception that

NEMMCO's exposure to the debited participant increases and NEMMCO's exposure to the credited participant decreases. Typically the debited participant would be a generator, and NEMMCO would be able to set off the debit against other entitlements of the generator to receive payment from NEMMCO for electricity contributed to the grid. However, NEMMCO particularly has a credit risk to the debited participant if the debited participant ceases to generate electricity. Without any offsetting payments for electricity, the debited generator would quickly assume a large liability to NEMMCO. For this reason, although reallocation should reduce the size of the prudential requirements and credit support that NEMMCO requires in respect of the credited participant (the distributor), the reallocation may increase the amount of credit support that NEMMCO would require from the debited participant (the generator).

The process of introducing a reallocation transaction into the national market is likely to require:

1. a request for reallocation (specifying the time, quantity and region) being lodged with NEMMCO by the debited and credited participants jointly;
2. the debited and credited participants agreeing between themselves some alternative arrangement outside of the market for the credited participant to pay the debited participant for the quantity of electricity (typically by changing the reference price in a bilateral swap from the spot price to zero);
3. NEMMCO considering the reallocation request and approving it for registration as a market transaction where NEMMCO is satisfied that it holds sufficient credit support from the debited participant and that it is within trading limits;
4. NEMMCO de-registering the reallocation and forcing the market participants to trade with the market on an unreallocated basis where the debited market participant defaults on its obligations to NEMMCO (especially where it stops generating);
5. the result of the reallocation transaction is a positive trading amount for the credited participant and a negative trading amount for the debited participant - these are aggregated and paid or collected upon settlement for the trading period.

Prudential requirements

Each of the four transactions in the national electricity market (spot market, short term forward market, inter-regional hedges and reallocations) gives rise to a positive or negative trading amount for a market participant in respect of a trading interval. At the end of each week, the positive and negative amounts for each trading interval in that week (there are 336 trading intervals per week) are aggregated, and if the net result is negative then the market participant must pay that amount to NEMMCO. If the net result is positive then NEMMCO pays that amount to the market participant. The settlement payments are to be made 20 business days after the close of the trading week.

How does NEMMCO ensure that it can collect sufficient trading payments to pay the amounts owed to other market participants? There are two principal methods. First, NEMMCO's liability to make a payment on the settlement of trading amounts is limited by a limited recourse process under which it is not obliged to pay out more to market participants than it collects from market participants. If there is a shortfall in collections, the shortfall is pro-rated amongst all market participants entitled to receive a payment, in proportion to their payment entitlement. It has not yet been finally determined whether the pro-rating will be across the week in respect of which the default occurred, or some longer period, up to, say, three months.

The second method of ensuring payment is to require that all trading amount payment obligations of market participants meet an "acceptable credit criteria", or else be collateralised by credit support in favour of NEMMCO from an entity that does meet the acceptable credit criteria. The acceptable credit criteria is primarily that the entity providing or guaranteeing the payment obligation:

- has an acceptable short-term counterparty credit rating from an external rating agency (likely to be initially set at Moody's P-1 or Standard & Poors' A-1); and
- is a bank under the prudential supervision of the Reserve Bank of Australia, or is a State or federal government.

Participants that hold credit ratings below the required level can still participate in the market, but the participant must obtain a guarantee from a bank or government that meets the acceptable credit criteria.

Where credit support is provided by a guarantor, this will usually contain a limit on the liability of the guarantor. The amount of credit support provided for a market participant must in aggregate be at least the amount of the "maximum credit limit" for the market participant. The maximum credit limit for a market participant is set by NEMMCO from time to time pursuant to a formula that endeavours to calculate the reasonable worst case exposure of NEMMCO to the market participant. This formula is anticipated to have regard to a range of factors, including the length of the billing and payment cycles, the participant's trading history and usual level of outstandings, the history of spot prices and the volatility of the spot price. If at any time a market participant's outstandings approach within a prudential margin of the maximum credit limit and credit support held, NEMMCO can require an interim settlement of outstandings of the market participant to bring its outstandings back to the anticipated level, or accept an increased level of credit support to restore the prudential margin between the outstandings and the level of credit support held.

OFF-MARKET (BILATERAL) CONTRACTS

Financial contracts

The preceding sections of this paper have examined the transactions that are proposed to be supported by the national electricity market operated by NEMMCO. However, although there will be spot market transactions at the variable spot price representing each flow of electricity in the grids, a significant quantity of that electricity will be the subject of off-market financial transactions under which participants hedge their exposure to the variable spot price, by bilateral contracts directly between market participants rather than with NEMMCO.

These bilateral contracts are usually a form of "contracts for differences", under which the seller compensates the buyer if the market spot price is higher than the agreed or strike price, and the buyer compensates the seller if the market spot price is lower than the strike price.

Vesting contracts

Upon the commencement of each of the Victorian and New South Wales markets the participants in those markets were "vested" with a series of bilateral contracts arranged by the government reform groups. Each "vesting contract" represented a contract for differences between a distributor and a generator for a profile of loads at a agreed prices. Each distributor was typically vested with contracts for a proportion of their estimated load with each generator. In both markets a quantity of the estimated load required by the distributor was left uncontracted by vesting contracts, requiring the distributor to manage the spot market price risk for that uncontracted component.

Although the terms of the vesting contracts in the Victorian and New South Wales markets are not publicly available, the issues that typically arose in considering the terms of the contracts included these:

1. Were the quantities under the vesting contracts to be "firm", or should they be capable of "flexing" so that the distributor could require that the contract give price coverage for additional quantities actually consumed by the distributor up to an agreed margin beyond the quantity which must be settled?
2. How many load profiles were to be used as the quantities under the contract - were there to be multiple load profiles reflecting seasonal differences, monthly differences, differences between different days of the week et cetera?
3. Would each party bear its own tax risk, or the risk against imposition of any environmental or greenhouse gas levy, or if these taxes or levies were imposed would the cost be passed through to the other counterparty to the contract?

4. If the generator was affected by industrial dispute, materials supply failure, force majeure or other reasons preventing generation, should the contract for differences continue to operate?
5. Should the contract for differences operate for all spot prices up to the market maximum price (VoLL), or should the parties share the risk of high prices beyond a particular point?
6. Should the contract require the generator to actually make physical delivery of electricity to the grid (by submitting a zero bid in order to force the system operator to schedule it), or should the generator be able to elect not to generate and instead accept the financial consequences (a likely higher spot price, for which the generator must pay the distributor the differences)?
7. At times of high spot prices the difference payments payable by the generator to the distributor would be substantial - should the generator supply credit support to secure this payment to the distributor?
8. At what times should the settlement payments on the contracts for differences be paid, bearing in mind that the distributor is liable to pay the spot price to the market on the market settlement dates and may require cash flow from the generator in order to meet possible high spot prices?
9. For how long should the quantities in the vesting contract remain valid, given that the opening up of customers to competition may mean that a distributor may lose customers for which it is presently contracting?

The quantities contracted under the vesting contracts are proposed to lessen to nil over the next several years, requiring the counterparties to severally negotiate new arrangements.

Swap or two-way hedge contracts

The vesting contracts can be described variously as a form of "swap agreement", "two-way hedge contract" or "cash-settled forward purchase contract". They swap a floating price exposure (a stream of payments to or from the spot market) for a fixed price agreed between the participants. The difference payments under the contracts allow a market participant to hedge its exposure under the national market with an off-market contract for differences. They follow the form of other forward purchase commodity agreements where the parties agree now to buy or sell a quantity of a commodity in the future, but instead of taking delivery of the quantity the parties settle on a cash basis by reference to an agreed quantity and the market price at the settlement date versus the agreed price under the swap contract.

These bilateral swap contracts enable the market participants to fine-tune the quantities for which they are already contracted under the vesting contracts. For example, if the vesting contract quantity did not cover all of a distributor's quantity typically consumed on a Tuesday night, it would be possible for the distributor to enter a bilateral swap contract with another market participant to "purchase" or fix the price for an additional quantity of electricity for those trading periods on Tuesday nights. The counterparty could be a generator, or it could be another distributor that is already "overcontracted" for those trading periods. As the bilateral contracts do not require physical delivery of electricity, it is possible to contract several times over for the same quantity of electricity, leaving a net position after calculating through the transactions at their different strike prices.

Swaptions

It is conceivable that the market participants may develop a form of option or "swaption" under which a market participant (in consideration of the payment of a fee) could exercise a right at some time in the future to require another participant to enter into a swap (or fixed price bilateral contract) for a fixed price hedge at that future time. Such an arrangement is sometimes also called an "American Option" or "Put Option".

Conceivably this option contract could be used as some form of insurance or protection against a period of high prices, perhaps exercised by a generator at a time that the generator has an outage and suddenly needs protection against high pool prices at that point (rather than protection against high prices all of the time, which is what a standard swap would offer). Presumably the counterparty to such an option would be another generator (say a hydro or gas generator) that was prepared, in consideration of the initial premium, to start up additional capacity on short notice and generate at the lower fixed swap price agreed under the option rather than collect the very high market price. Other possible counterparties include distributors with dispatchable loads that would be prepared to receive the compensation under the option for switching off loads at times of high market prices.

The new ISDA/AFMA Part 19A

As the national grid develops in Australia and the financial transactions become more divorced from the physical delivery of electricity, we are now seeing a move away from the standard power purchase agreements and a move towards 'financial" contracts dealing with adjustment for price and quantities only. Delivery of electricity is becoming less critical at this time when there is an over-capacity of generation. It is also now easy to define the damages suffered by non-delivery, because the market delivers the quantity from a third party and sets a marginal price for the delivery.

With the emphasis on financial adjustment rather than delivery, and a desire to develop a standard form of bilateral contract that would permit a fluid contractual market, a number of market participants in Australia are turning to the Master Agreement developed by the International Swaps and Derivatives Association Inc (ISDA), which in Australia is published by the

Australian Financial Markets Association (AFMA). AFMA is now publishing a "Part 19A" guide to completion of AFMA/ISDA documentation, suggesting how market participants can document commodity transactions where the commodity is electricity in Australia under a market pool (initially the New South Wales market).[9]

The AFMA Pt 19A is based upon the Pt 19 relating to commodities generally, and recommends methods of dealing with matters such as:

- payments on early termination (market quotation, second method to apply);
- how market quotations are to be obtained for use on early termination;
- market disruption events and price source disruption;
- tax disruptions such as the imposition of a carbon tax or greenhouse gas levy; and
- definition of the price source and the commodity reference price.

One of the major areas of departure from the traditional power purchase arrangements is that the AFMA/ISDA documents in the recommended form effectively leave force majeure as a risk to be managed by the participants themselves rather than passed through to the counterparty participant. The counterparties are no longer under an express obligation to deliver or take electricity, but simply to pay the financial consequences of the market prices departing from the strike prices. If this form is widely adopted, generators particularly will need to develop other methods of risk management, such as insurance, co-insurance or some form of option or swaption arrangements to cover the financial risks of high spot prices at a time when the generator is unable to generate.

Another area that will undoubtedly require further contractual development relates to early termination of a long term swap contract or other derivative. In many other commodity markets there are long term market indicators (such as the five year swap rate or the ten year government bond rate) that can be used to measure the present value of the future component of an uncompleted transaction, and determine compensation to a participant for loss of the contract in circumstances where it is terminated early. In the Australian electricity markets there are as yet no such indicators, and the current fallback recommended in the AFMA/ISDA Pt 19 is to a "Reference Market-Maker" (presumably another market participant) to determine and quote an amount that is the economic equivalent of the future value of the contract, or the present value of the uncompleted transactions. Until the markets develop some standardised benchmark indicators and long-term bid and transaction information, the result of such an early termination quotation is likely to be uncertain and difficult to ascertain.

9. *Australian Financial Markets Association*, March 1996, NSW Electricity Market Addendum No 1.