The dynamic efficiency gains from introducing capacity payments in the NEM Gross Pool

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Abstract

By any standards, Australia's National Electricity Market (NEM) has been a beacon for those Governments in the Asia-Pacific region considering reforming their power generation industry. Since the NEM commenced, plant availabilities have risen to world benchmark levels, generator cost structures have fallen sharply, prices are among the lowest in the world, and the oversupply of generating plant has virtually cleared. What makes this outcome so impressive is the perilous state that Eastern Australia found itself in at the onset of reform during the mid-1990s. However, while the energy-only gross pool market has served Eastern Australia well over the past decade, deep structural faults on the supply-side remain, and appear to be deteriorating. The reason for this outcome is that competitive energy-only markets do not have a definable equilibrium solution unless reliability constraints are violated, or market power is exercised. The densely compressed marginal running cost curves of the base, intermediate and peaking plant stock make cost recovery an almost impossible task for all plant, and particularly for peaking plant. Without policy intervention, the NEM is headed for periods of supply shortages and unacceptable levels of load shedding. This represents a political hazard for State Governments, who are ultimately held accountable for the performance of the deregulated NEM. This research finds that by reducing the Value of Lost Load and introducing a Capacity Payments Pool, a tractable equilibrium can be established that will ensure the timely entry of new plant.

1. Introduction

Over the seven years that the National Electricity Market (NEM) has been in operation, state-based monopoly power generators have been restructured and reformed, costs have fallen, prices reflect more competitive levels and plant oversupply, which had plagued the industry in South-Eastern Australia, has virtually cleared at the aggregate level. Thus, one could rightly conclude that the usual reform objectives of enhancing productive (cost), allocative (price) and dynamic (expansion) efficiency have been achieved. But while there is little doubt that productive and allocative efficiency improvements in all regions of the NEM have been marked, the dynamic efficiency of the NEM has been adequate at the aggregate level, but sub-optimal when the structure of the supply-side is analysed.

At the aggregate level, the NEM has, on balance, delivered sufficient generating plant capacity between 1998 and 2006, notwithstanding the dramatic events in Victoria during the summer of 2000/01 when capacity stocks were largely exhausted. But system reliability has had more to do with the high-quality oversupply of monopoly plant that the NEM inherited at inception, along with an *excess entry result* in Queensland, as opposed to a smooth and timely *invisible hand* that might loosely be associated with an 'energy-only' market.

While it is all well and good for 'free-marketeers' to suggest that consumers should somehow accept lesser reliability levels and higher prices periodically, it is politicians who are ultimately

[1] The views expressed in this paper are those of the author and not necessarily those of NewGen Power.

held accountable when the electricity supply industry underperforms vis-à-vis societal expectations. In Eastern Australia, the average domestic consumer still considers electricity 'an essential service' rather than a tradable commodity. Considered in this light, an adequate reserve plant margin is an externality to electricity production and consumption in the energy-only NEM. Consumers prefer adequate reserves but currently are not charged for capacity. And when a generator makes an investment which has the effect of providing additional reserves, they are inadequately remunerated unless market power is exercised. In fact, on the contrary, because generation plant investments are usually 'lumpy', post-entry spot and contract prices invariably fall below system cost (Simshauser, 2001). Under such conditions, Bidwell and Henney (2004, p. 11) have noted the logical conclusion:

> *…As is well known from standard economic text books, the presence of a large externality is one of the problems that a market cannot, by itself, deal with; and, if left alone, such an externality will be a predictable cause of market failure…*

Thus is the objective of this research; since energy-only markets give rise to a large externality (i.e. adequacy of reserve plant capacity), is market failure predictable? This paper is structured as follows: Section 2 reviews the gains required from reform. Section 3 addresses the performance of the NEM between 1998 and 2005. Section 4 examines the reasons behind the inadequate entry of peaking plant and Section 5 identifies the unique economic characteristics of peaking plant, and their poor outlook in energy-only markets. Section 6 and 7 examine the impact of Full Retail Contestability and Vertical Integration on peaking plant entry respectively. Section 8 discusses the inherent instability of energy-only markets, while in Sections 9, 10 and 11, modeling results of a combined energy and capacity payment market are presented and analysed. Section 12 canvasses the implications of introducing capacity payments on various sectoral interests, and conclusions follow in Section 13.

2. Gains required from microeconomic reform of the power generation industry

During the 1980s and 1990s, the status of the monopoly power generation industry in South-Eastern Australia was bordering on critical. For example, by the mid-1980s New South Wales had invested in so much baseload capacity that it would take more than 20 years to clear. And by the early 1990s, Victoria had invested so excessively in baseload plant that the State Credit Rating was down-graded, and a Labor Government was virtually forced to privatise its newest power station as a result. Electricity tariffs were substantially above competitive levels and consequently, the requirement for, and objectives of, reform were clear.

It is useful to examine the dynamic efficiency of the aggregate East Australian generating plant portfolio in 1997/98, just prior to the commencement of the NEM.[2] Table 1 depicts the optimal mix of base, intermediate and peaking plant for the NEM in 1997/98 and contrasts this with the actual stock of plant that existed at the time.[3]

[2] The NEM commenced in December 1998 and comprised the eastern and southern Australian states of Queensland, New South Wales, Victoria and South Australia. Tasmania joined the NEM in 2005/06 following the commissioning of the Basslink Interconnector.
[3] The costs and framework used to derive the optimal plant mix are discussed later, in Sections 8 and 9 respectively.

Table 1: NEM generating plant portfolio balance in 1997/98

NEM 1997/98	Optimal (MW)	Actual (MW)	Portfolio balance (MW)
Baseload	20,400	24,500	4,100 *overweight*
Intermediate	2,000	2,100	100 *overweight*
Peaking	8,200	6,600	-1,600 *underweight*
Total	30,600	33,200	2,600 *oversupplied*

The NEM generating portfolio was substantially *overweight* base plant, with around 4100MW of excess supply – located mainly in the states of Victoria and New South Wales. Intermediate plant was roughly even, while peaking plant was *underweight* by 1600MW, with the system being oversupplied in aggregate by around 2600MW against a coincident peak load of about 25,000MW. The market value of these 'structural faults' can be quantified at \$5.1 billion or 13% of the \$43.9 billion NEM power station portfolio.[4]

3. The performance of the NEM: 1998-2005

At the start of the NEM in 1998, spot prices in the Queensland region rose to extreme levels due to delays in the interconnection of the Queensland and New South Wales power systems.[5] If this delay had not occurred, the entire structure of the Queensland system may now be quite different.[6] Excess base plant in Southern-Australia during the late-1990s would have been able to export their surplus capacity northwards, as was originally envisaged. There was no doubt that Queensland urgently required new baseload power, either by way of interconnection to access surplus capacity from New South Wales, or in the absence of this, through new investment within Queensland. But the spot prices that subsequently emerged in Queensland immediately after the reforms commenced were so lucrative (due to inadequate supplies of baseload plant) that the outcome was literally an *excess entry result* and a game of *billion dollar chicken* amongst multiple, low cost, coal-fired, potential new entrant generators.[7] The history of NEM spot prices is provided in Table 2; note in particular the very high spot price in Queensland during 1998/99:

Table 2: Spot prices in the NEM

Price (\$/MWh)	1998/99	1999/00	2000/01	2001/02	2002/03	2003/04	2004/05
Queensland	59.84	44.11	41.33	35.34	37.79	28.19	28.96
New South Wales	24.32	28.28	37.69	34.76	43.91	32.37	39.33
Victoria	24.51	26.35	44.57	30.97	27.56	25.38	27.62

Perhaps not surprisingly, between 1998 and 2001 an additional 2100MW of very low marginal running cost baseload plant was committed, and added to the plant stock in the Queensland region by 2003/04 against a requirement of only 820MW.

Another important event that occurred in the NEM was high spot and contract prices in Victoria during 2000/01, a point in time where the existing plant stock in that region was largely exhausted. That prices in Victoria rose so sharply, from mid-\$20 spot prices in 1998/99 and

[4] Unless otherwise marked, all cost and price data is expressed in 2006/07 dollars.
[5] The Queensland-New South Wales Interconnector (QNI) was re-routed from an eastern corridor (Eastlink) to the west (Westlink) due to public objection.
[6] The issue here is that if the QNI had been commissioned prior to NEM start, spot prices in Queensland would have been very low. As a result, many of the new stations would not have found it economic to enter in the first place.
[7] A full discussion of the *excess entry result* and *billion dollar chicken* in Queensland is provided in Simshauser (2001) and Simshauser (2006a) respectively.

1999/00, to almost $45.00/MWh in 2000/01, is typical of the result that occurs when a system is heavily *overweight* base plant, but faces looming capacity constraints in aggregate. When base plant capacity excessively dominates the aggregate supply function in an energy-only gross pool market, these low-cost machines tend to cannibalise the important 'price-setting' role of higher marginal cost intermediate and peaking plant. Consequently, base plant capacity sets price too-low, too-often. While a *physical system analysis* can clearly point to a near-term supply shortage, the economics of the energy-only market 'fails' in that the signaling for new plant occurs very suddenly. New peaking plant capacity was ultimately commissioned in Victoria, although it is generally accepted that from a security of supply perspective, it arrived '5-minutes after midnight'.

With the benefit of perfect hindsight, over the period between 1997/98 and 2004/05 the NEM *physically required* the addition of 3800MW of peaking plant and 400MW of intermediate plant capacity. Had the QNI been commissioned in line with the eastern corridor proposal, no new base plant would have been required over this timeframe. In the absence of this, 820MW of base plant was required in Queensland, and additionally, it would be fair to conclude that a further 840MW of new base plant would need to be commissioned in the NEM during 2005/06. However, as Table 3 clarifies, actual investments in new plant have deviated substantially from the cost-minimising solution. The complete stock of new entrant plant in the NEM, including capacity (MW) and the replacement value ($M) is illustrated in Table 3.

Table 3: New entrant plant in the NEM and the requirement for new plant

Entrants	Year	Region	Ownership	SCpf (MW)	NGCC (MW)	OCGT (MW)
Roma GT	1999	QLD	Private			80
Swanbank D GT	1999	QLD	Public			34
Oakey GT	2000	QLD	Private PPA			282
Ladbroke Grove GT	2000	SA	Private			80
Pelican Point CCGT	2000	SA	Private		478	
Port Lincoln GT	2000	SA	Private			50
Callide C	2001	QLD	50% Private	840		
Redbank	2001	NSW	Private PPA	150		
Bairnsdale GT	2001	VIC	Private			92
Quarantine GT	2002	SA	Private			96
Swanbank E CCGT	2002	QLD	Public		376	
Millmerran	2002	QLD	Private	840		
Tarong North	2002	QLD	50% Private PPA	443		
Valley Power GT	2002	VIC	Private			300
Somerton GT	2002	VIC	Private			160
Hallet GT	2002	SA	Private			183
Yabulu CCGT	2004	QLD	Private PPA		247	
TOTAL (MW)	4,731			2,273	1,101	1,357
Required (MW)	4,200			0*	400	3,800
Surplus/Deficit (MW)	531			2,273	701	-2,443
INVESTMENT ($M)	5,583			3,410	1,156	1,018

*New base plant would be required in 2005/06.

Based on the difference in system demand between 1997/98 and 2004/05, the required increase in plant to service aggregate demand amounts to 6900MW. Bearing in mind that the system was already oversupplied by 2700MW in 1997/98, only 4200MW of additional plant investment was required, whereas 4731MW has been delivered. However, of this amount, 679MW has been delivered by government-backed Power Purchase Agreements, and 1283MW was delivered in a *billion dollar chicken* competition in Queensland, an incidence which is unlikely to be repeated.[8] Table 4 provides the portfolio balance for the NEM as at the end of the 2004/05 financial year:

Table 4: NEM generating plant portfolio balance in 2004/05[9]

NEM 2004/05	Optimal (MW)	Actual (MW)	Portfolio balance (MW)
Baseload	23,300	26,700	3,400 *overweight*
Intermediate	2,300	3,200	900 *overweight*
Peaking	11,900	8,000	-3,900 *underweight*
Total	37,500	37,900	400 *oversupplied*

Despite these variations, from a dynamic efficiency perspective the 2004/05 outcome represents a substantial improvement on the 1997/98 result in that system oversupply has reduced from 2700MW down to just 400MW. And the investment value of supply-side 'structural faults' has reduced from $5.1 billion (13% of aggregate investment) to just $3.1 billion (7% of aggregate investment). Strictly speaking, this represents a dynamic efficiency gain of $212 million per annum via lower annual capital charges. And there are many other performance statistics which have improved dramatically since the reforms were implemented, as noted in Simshauser (2006b):

- Plant availability in Victoria and in New South Wales has increased from below 80% in the early 1990s to around 90%. The effect of this increase in availability is equivalent to adding 1800MW of base plant to the system, and thus notionally avoiding $2.7 billion in capital investment, which translates to an annual saving of $216 million in capital carrying costs;

- From a productive efficiency perspective, operational costs have reduced sharply; for example, the trajectory of average cost of the monopoly generator in Queensland would have been $550 million higher in 2004/05 than those of the consolidated financial results of the restructured entities (i.e. Tarong, Stanwell and CS Energy), with the cumulative total since reforms amounting to $2.2 billion in Queensland alone. As the Queensland Electricity Commission was considered to be one of the most efficient electricity generators in the world at that time, and was about 1/3 of the size of the Victorian and New South Wales monopoly generators, there is little doubt that the operational cost savings in those states would have been multiples higher; and

- From an allocative efficiency perspective, spot and contract prices in the wholesale market have followed cost structures down, and are now at both competitive and world benchmark levels. At the time of writing, average spot and forward prices, against an average system cost of about $40.00/MWh[10], were as follows:

[8] The harsh experience of Project Banks in the NEM between 1998 and 2003 should ensure this is the case.
[9] Reserve margins used to calculate this aggregated result are 15% for New South Wales, 17% for Victoria and South Australia, and 19% for Queensland.
[10] Table 9 defines the idealised system cost ($/MWh) for each region and for the NEM as a whole.

Table 5: Wholesale market prices

Region	2005/06[11] Spot Price ($/MWh)	2006/07 Forward ($/MWh)	2007/08 Forward ($/MWh)	2008/09 Forward ($/MWh)
Queensland	30.63	36.25	34.50	35.00
Victoria	34.63	33.75	34.00	33.25
New South Wales	42.45	39.10	38.25	38.50

- Spot and forward price source: Man Financial- Physical Report (13 March 2006) & Futures Report (10 March 2006).

But despite this, there is a worrying trend emerging in Table 4. Peaking plant as a class is now under-represented by 3900MW as opposed to the 1997/98 result of 1600MW.

4. Market failure: the inadequate entry of peaking plant

An area that has received relatively little attention in NEM circles is the relative dynamic performance of peaking plant entry in the NEM. As Peluchon (2003) noted in the case of Europe, where similar problems are emerging, this is because newly deregulated energy-only markets have largely thrived on generation capacity built up by the public monopolies that previously existed. In the case of the NEM, this came in the form of a substantial over-investment in base plant in New South Wales and Victoria. But the excess capacity stocks highlighted in Table 4 will be exhausted over the course of the next year. And that peaking plant has shifted from *1600MW underweight* in 1997/98 to *3900MW underweight* in 2004/05 – in a climate of rising peak loads, limited demand for long-dated hedging and increasing Vertical Integration – should be deeply concerning to Consumers, Retailers, State Governments, Energy Regulators and Policy Makers alike.

Perhaps more concerning is that the peaking problem is likely to deteriorate further, as Sections 5-8 later explain. While the inclusion of Tasmania in the NEM will provide short-term relief through their hydro portfolio, which again, represents a monopoly-built plant stock, the extent of the *peaking problem* is put into sharp perspective when the optimal plant mix for the NEM in 2014/15 is forecast and compared against the existing 2004/05 plant stock, as in Table 6. Importantly, the analysis in Table 6 assumes an unconstrained transmission system, and that no existing plant is decommissioned. Any deviation from these assumptions will merely add to the $7.7 billion investment requirement.

Table 6: Optimal plant stock in 2014/15 vs actual plant in 2004/05 (incl. Tas)

NEM	Optimal 2014/15 (MW)	Actual 2004/05 (MW)	Portfolio balance (MW)
Baseload	29,500	27,600	-1,900 *underweight*
Intermediate	3,100	3,200	100 *overweight*
Peaking	16,100	9,700	-6,400 *underweight*
Total	48,700	40,500	-8,200 *undersupplied*

If, for example, the NEM transmission system remains in its current (grossly inadequate) state, an additional 3400MW of intermediate and peaking capacity would need to be added to the results in Table 6 in order to ensure an adequate reliability of supply, thus taking the total new plant requirement from 8200MW to around 11800MW at $10.4 billion, and the peaking deficit from 6400MW to an overwhelming 9600MW. Given the current rate of transmission investment, this latter result seems most likely. So why has this peaking plant deficit emerged, and more importantly, why is the situation likely to deteriorate? The inadequacy of peaking plant entry,

[11] Year-To-Date.

and its poor entry outlook, can be traced more definitively back to key economic characteristics associated with outcomes in the energy-only market, which is discussed below.

5. The defining characteristics of peaking plant in energy-only gross pool markets

Because peaking plant only produce when demand is exceptionally high, their merchant profitability is manifestly *random*. And high baseload plant availabilities compound the issue. Peluchon (2003, p.2) has noted that:

> *…Peak capacity investment, especially, seems quite problematic. An investment in base generation plant is a decision that requires forecasting base future prices. An investment in peak generation plant is a decision that requires much more information as peak prices depend on base prices as well as from the future investments in every other kind of generation capacity. The revenue generated by peak plant is therefore much more hazardous than base plant, since it produces only when every other plant produces at full capacity or cannot produce. In the same way an option is said to be 'out-of-the-money', peak plant has a value that may change drastically with any change in the way the supply-demand balance evolves...*

The extent to which a peaking plant can be *in-* or *out-of-the-money* is quantified in Table 7. Here, a 300MW Open Cycle Gas Turbine (OCGT) is simulated, and assumed to be dispatched at its *marginal cost of production* of $65.00/MWh, 'back-cast' against the historical spot price outcomes in Queensland. Table 7 includes operational data (run time, capacity factor, energy sent out, unit starts and gas demand) and financial data (revenue, variable costs, earnings, benchmark returns representing fixed costs and capital charges, and the annual profit and loss). Finally, and most importantly is the market data, with the most significant statistic being the fair-value (i.e. premium) of a $100.00/MWh-strike Cap derivative.

Table 7: Operating and financial data for a simulated 300MW OCGT in Queensland

SRMC ~ $65.00/MWh	1998/99	1999/00	2000/01	2001/02	2002/03	2003/04	2004/05
Operational Data							
Run Time (hrs)	933	844	767	293	285	156	144
Capacity Factor (%)	5%	5%	4%	2%	2%	1%	1%
Energy (MWh so)	279,750	253,200	229,950	87,750	85,350	46,650	43,050
Starts (#)	482	386	370	170	190	100	70
Gas demand (PJ)	3.2	2.9	2.6	1.0	1.0	0.5	0.5
Financial Data							
Merchant Revenue ($M)	87.2	54.1	33.2	26.5	37.8	19.9	13.8
Fuel, Starts & VOM ($M)	20.7	18.3	16.8	6.6	6.6	3.6	3.2
Earnings ($M)	66.6	35.8	16.4	19.8	31.2	16.3	10.7
Benchmark earnings ($M)	28.1	28.1	28.1	28.1	28.1	28.1	28.1
Profit/Loss	38.5	7.8	(11.6)	(8.2)	3.1	(11.8)	(17.4)
Market Data							
$100 Cap Value ($/MWh)	$ 26.37	$ 13.94	$ 6.15	$ 7.98	$ 12.70	$ 6.57	$ 4.23
Average Spot ($/MWh)	59.84	44.13	41.33	35.34	37.79	28.18	28.96
Average Peak ($/MWh)	76.73	59.50	58.70	45.09	51.50	37.17	37.80
Spot Standard Deviation	219.23	160.12	71.13	149.23	205.36	183.04	109.33
Volatility Index	3.66	3.63	1.72	4.22	5.44	6.50	3.78

Discounted cash flow modeling of a 300MW OCGT plant (using cost data from Table 8) indicates that to break-even, the value of $100/MWh Caps needs to be approximately

\$10.70/MWh on a continuous basis, and the plant needs to be fully hedged at this price.[12] Note from Table 7 that whenever the value of the Cap falls below \$10.70/MWh, the simulated plant incurs a loss. It is therefore not surprising that peaking plant proponents experience difficulties raising the requisite debt and equity finance in order to enter on an economic, and a timely basis, if at all. Neuhoff and De Vries (2004, p.3) pinpoint the most likely market outcome in deregulated energy-only markets in the absence of 'long-term' hedge contracts:

> *…[In the absence of long-term contracts] peaking plant is only remunerated in times of generation scarcity and hence face volatile returns. Investors therefore postpone their investment until the expected electricity price is higher, and require higher rates of return…*

Neuhoff and De Vries (2004) provide an insightful analysis as to the extent and impact of higher rates of return on ultimate plant cost and market prices in England & Wales. They explain that the uncertain revenue stream is anticipated by investors, and following anecdotal evidence, conclude that the weighted average cost of capital increases by around 7% for peaking plant investments in the absence of long-term contracts. At the efficient rate of investment with long-dated Cap contracts, the annual carrying cost of a peaking plant in the NEM is, as noted above, likely to be in the order of \$10.70/MWh. But following the conclusions from Neuhoff and De Vries (2004), the carrying cost of purely merchant peaking plant would increase to \$16.50/MWh.[13] This being the case, the wholesale average electricity price would need to rise substantially (i.e. by \$5.80/MWh per annum) prior to new investments in peaking plant occurring. In consequence, long-dated hedge contracts or some other long-term market mechanism (e.g. capacity payments) are essential in order to minimize the cost of new entrant peaking plant, otherwise electricity prices will increase, and system reliability will necessarily deteriorate.[14]

6. The requirement for *courageous retailers* with 'FRC' in energy-only markets

In order to achieve maximum dynamic efficiency in the deployment of peaking plant, long term debt finance is required, and like any other capital intensive investment, with gearing ratio's of 60-70%. But in order for these fundamental financing conditions to hold for a peaking plant development in light of its otherwise 'hazardous' merchant revenue stream, it is essential that a long-dated hedge contract be signed with a retailer. Generally speaking, in order to secure 10-year money, the term of hedge contracts would need to be 7-10 years. But the advent of Full Retail Contestability (FRC) in the energy-only NEM raises obvious problems for electricity retailers in terms of signing a large portfolio of 10-year hedge agreements.[15] Neuhoff and De Vries (2004, p.18) noted that if a retailer has signed a portfolio of long-term hedge contracts, and market prices fall in any given year, fiscal problems can emerge:

[12] This is obviously a problematic assumption because of the inherent price risk associated with a coincident unit outage and a \$10,000/MWh (Value of Lost Load) price spike.

[13] These results were calculated using a discounted cash flow model of a 450MW peaking plant as per the data contained in Table 8, using discount rates of 11% and 18% respectively.

[14] One might argue that government-owned generators are able to develop peaking plants without hedge contracts and at lower cost due to their ability to finance such machines on-balance sheet, with debt obtained through State borrowing agencies, thus funding the project at the corporate cost of capital. However, this is merely crystallizing an implicit Government subsidy, with taxpayers bearing the market risk of the plant's ultimate performance. Taking this argument to its illogical extreme, Governments should fund *all* risky projects.

[15] Invariably, all retailers can absorb a certain amount of long-dated contracts if they are satisfied that the price of the hedge contract reflects an efficient new entrant cost structure. The issue here is whether they can absorb an additional 9600MW of long-term contracts in the space of eight years, that being the shortfall of peaking plant between now and 2014/15 as per Table 6, under conditions of ongoing transmission constraints.

> *…new retail companies may enter the market and offer cheap retail electricity. If the regulatory agencies succeed in achieving Full Retail Competition, then switching costs will be low for consumers and they will move towards these new retail companies. Under such circumstances, all retail companies would need to follow. Retail companies with [a large portfolio of out-of-the-money] long-term contracts would incur losses. Some would eventually go bankrupt and would not honor their contracts…*

Anderson, Hu and Winchester (2006) undertook extensive market research amongst NEM participants and confirmed a tension between retailers and generators in relation to the optimal term of hedge contracts. In the case of retailers, they found preferred terms of just 1-3 years, as this was the longest time-horizon over which they have a degree of clarity on load profiles and over which the interaction between supply and demand could be reliably forecast, including the advent of new supply-side entrants. Additionally, a difficulty faced by retailers with significant contestable loads is that large customers may be won or lost at relatively short notice, again impacting their forecast load. Indeed, one retail trader was quoted in the Anderson et al. (2006, p.19) research as saying:

> *…Not too many people want to go out past three years because the water is getting a bit murky out there…*

Newbury (2002) considered the impact of limited long-dated hedge contracts under FRC and an energy-only market in England and Wales and concluded it to be sufficiently problematic as to necessitate institutional change amongst deregulated energy-only electricity markets. The change envisaged was one that would create a credible counterparty for generators to sign long-term contracts, viz. by reinstating regional monopolies to electricity retailers so that domestic consumers would not have the option to switch.

A small number of *courageous retailers* in the NEM have signed long-dated hedge contracts in order to facilitate the timely entry of cost-efficient peaking plant. These NEM retailers, typically with a dominant local position, have evidently undertaken a thorough assessment of the supply-side structure, and concluded that new peaking capacity is critical. However, courageous retailers bear a heavy burden. All other competing retailers operating in the region, particularly smaller players who focus on hit-and-run tactics, are able to free-ride off the actions of the courageous retailer. At a minimum, the cost of marginal system reserve is ultimately being carried by the courageous retailer. But under such circumstances, the Neuhoff and De Vries (2004) scenario may begin to materialize, and if so, the retailer would commence a slow downward spiral through loss of market share, margin squeeze, and potentially, financial distress.

A key policy issue that remains therefore is that of generation adequacy. Even if a courageous retailer existed in every region of the NEM, and that retailer was indeed dominant, it is difficult to imagine this single entity taking the full responsibility for ensuring that adequate plant capacity existed at the whole of region level.

7. The effects of Vertical Integration on reliability in energy-only gross pools

Vertical Integration (VI)[16] has become a dominant strategy for retailers in the NEM. At one level, VI is a natural outworking of the NEM energy-only gross pool and provides a method of reducing the cost and uncertainty of contracting, notwithstanding the fact that the two businesses require entirely different skill sets.

[16] For the purposes of this research, VI refers to the situation whereby retailers build, acquire or secure the dispatch-rights of generating plant - primarily being gas-fired intermediate and peaking plant.

The origins of VI seem clear enough. During the late-1990s in the Victorian region, spot prices had reached critically low levels, as Table 2 noted earlier. What Table 2 did not show is just how low prices fell in prior years. During the 1997/98 financial year for example, the (pre-NEM) Vic-NSW market result was just $14.50/MWh in the spot market and around $18.00-20.00/MWh in the hedge market. At this point in time, the Government, the Power Exchange, and all generator and retailer participants in the region were well aware of the requirement for new peaking plant by the summer of 2000/01. But the gross pool was delivering such low spot and hedge contract prices in prior years that, unsurprisingly, no entity was willing to invest in the required capacity in a timely manner (i.e. timely in a *physical* as opposed to *financial* sense). This Victorian paradigm was so significant that it was labeled *The Top End Problem.* Predictably, inadequate generating plant capacity was soon followed by inadequate hedge capacity – a situation not previously contemplated by the then stand-alone electricity retailers. To compound the risk that retailers were facing, a case was put forward to the regulator to raise the Value of Lost Load (VoLL) from $5,000/MWh to $30,000/MWh on the basis that the infrequency of price spikes, and the cost of new peaking plant, would need rises of this magnitude in order to justify new investment.[17] In the end, the regulator accepted the argument that VoLL needed to be raised, albeit to $10,000/MWh. The change was implemented in April 2002.

The combination of excess base plant in the Victorian region driving critically low underlying spot prices, an energy-only market environment with limited ability for any generator let alone peaking plant to recover its reasonable costs, the absence of new entrant peaking plant, a growing deficit in the availability of much needed hedge contracts, and finally, the announcement that VoLL would be lifted to $10,000/MWh all culminated in the space of three months during the 2000/01 summer. This sealed the fate of VI as a business strategy for retailers in that region. Like the domino effect, now that VI has become a dominant retail strategy in Victoria, all non-niche retailers in the NEM are now reassessing their positions with respect to the ownership of, or control over, generating plant as virtually a requisite condition of survival.

VI appears to be a logical and viable solution given the current market environment and current policy settings. And to be sure, there is no evidence that the strategy is, thus far at least, anything other than successful. But its long-run success in the NEM hinges critically on two issues which seem to be diametrically opposed:

1. From a participant perspective, for the VI entities to ensure that transfer pricing of in-house generating plant remains ‘in-the-money’, it is *almost a necessary condition* for capacity to be short-supplied to ensure cost recovery due to the nature of the energy-only gross pool market, as we will see in later sections of this research.[18] Neuhoff and De Vries (2004, p.20) examined the long-run profitability of VI in some detail in their research:

[17] Presumably such calculations were based on merchant revenues.

[18] The anti-thesis to this is that retailers use their ‘controlled’ peaking plant capacity to reduce the frequency and intensity of price spikes. Indeed, during several price spike events in Victoria during early 2006 , portfolio generators withdrew capacity to drive up the spot market while VI-controlled peaking plant were re-bid below marginal cost in order to moderate the spot market, as noted by Creative Energy Solutions (2006a, 2006b). When peaking plant is used to neutralise price spike events, underlying market volatility is reduced and in turn, so too is the premia and value associated with hedge contracts. In theory at least, this benefits the retailer but will adversely effect the profitability of portfolio generators. While a legitimate market strategy, the long-run impact of price-spike lopping could compound the damage of energy-only markets on reliability of supply – because the inadequate price signals that exist before the effects of VI are taken into account will be further *baffled* after the effects of VI are accounted for. In simple terms, neutralizing price spikes may artificially delay even further the optimal *financial* timing of entry, which as discussed previously, already lags the *physical* requirement for entry by a number of years.

> *…One might argue that vertical integration by generators into the retail sector, which is common, has the side-effect of effectively creating long-term contracts between generation and retail companies. However, if the retail market is competitive, then integration of retailers and generators does not provide the required long term contracts to secure investment, because final consumers are not included in the long term contract. At times of low wholesale electricity prices, final customers could continue to switch supplies and vertically integrated retail companies will also lose their customers. Therefore vertically integrated retailers and generators cannot offer electricity tariffs according to long run marginal costs, but will vary the tariffs with the average wholesale price…*

2. From a policy perspective, the preferences of consumers and therefore the objectives of government, regulatory authorities and policy makers vis-à-vis reliability of supply need to be met. If the market fails this underlying, and indeed paramount objective, participants must reasonably expect policy intervention in some form or another.

This latter point is worth analyzing further. If it were the case that, for example, electricity retailers were 'prohibited' from owning or controlling generating plant, they would be obliged to purchase all of their hedge requirements from incumbent or new entrant portfolio generators. Portfolio generators, as a principle, do not fully hedge their capacity for reasons of self-insurance. Anderson et al. (2006) noted that just as retailers face extreme spot price risk when under-hedged, generators face extreme price risk when they are over-hedged relative to available capacity. Consequently, portfolio generators typically follow an *n-1 hedging strategy* – thus holding final units in reserve to cover such outages. In particular, Anderson et al. (2006, p.26) found:

> *…from the interviews we carried out, it seems that on average [portfolio] generators are about 70-80% contracted…*

If portfolio generators withhold some component of their capacity, then by implication, some level of system reserve is being inherently supplied. In contrast, the nature of the VI strategy is to match swing load with intermediate and peaking plant capacity to reduce or even avoid the cost of underwriting a portfolio generator's self-insuring strategy. That being the case, as VI entities shift their intermediate and peaking hedge capacity requirements from portfolio generators to in-house subsidiaries, the required generation insurance strategy is effectively internalized (with offsetting demand management) without the non-firm risk being discounted to the same extent - understandably. Thus, if the trend of VI continues, it is possible that the market will become even further short-supplied in peaking plant, and by implication, so too will prevailing reserve plant margins at the whole of system level – a VI effect.

To explain the significance of the VI effect, consider a scenario whereby the marginal plant at each of the NSW portfolio generators (totaling 1200MW) is assumed to be reallocated to several VI entities. If this were the case, the level of available hedges from portfolio generators would decrease by only 600MW – the reduction of only 50% due to plant portfolio diversification.[19] However, in this scenario, once the marginal plant is allocated to the VI entities, the full 1200MW of plant would be incorporated in the hedge market, thus leading to a nett increase in market hedges of 600MW (i.e. -600 + 1200). Thus, to supply the same level of hedges, VI entities require 600MW of generating capacity. Thus, by backward induction and holding the

[19] Portfolio hedge thresholds can be calculated by joint-probabilistic Monte Carlo simulations of coincident unit availability. Solving for a confidence limit of between 90 and 95% in NSW confirms that the marginal change in aggregate hedge capacity from re-allocating the PPA machines, Hunter GT, Shoalhaven and Munmorah (about 1200MW in total) amounts to 600MW. This makes intuitive sense since the generators hold diversified plant portfolios and removing the final station does not *substantially* change this diversity.

level of hedge capacity constant, VI entities require 600MW less physical supply, which would send system reserves from 18% to just 13%.

If system reserves drop as a result of the VI effect, there is little doubt that the value of transfer prices within VI entities would be *deep-in-the-money*, and of course for Consumers, Government, Regulators and Policy Makers, the power system will most certainly experience widespread black-outs, save mild summer and winter conditions or extraordinarily high plant availabilities. But more importantly, as Bidwell and Henney (2004) have noted when a market reaches this juncture, portfolio generators exercise market power, and with insufficient installed capacity, prices boom. Following this is the *excess entry result* as noted in Simshauser (2001), a development boom where new entrants exceed system requirements by multiples. Predictably, what then follows is a bust and poor investor returns. Thus is the market cycle of Queensland (1998-2005) and Victoria (2000-2006). This leads to an economic analysis of the spot market, and a quantitative examination of why reasonable costs cannot be recovered when the market is competitive and reliability constraints are met.

8. The inherent instability of energy-only electricity markets

Simshauser (2001, 2006a), Bidwell and Henney (2004) and Booth (2005) have noted that energy-only markets are inherently unstable, and therefore the exercise of market power by generators is, to some extent, justified on the grounds that bidding at short run marginal cost cannot possibly lead to the recovery of reasonable costs. Bidwell and Henney (2004) examined the net pool arrangements in England and Wales and through the use of a static *idealized* perfectly competitive market model of a power system with no plant outages, demonstrated that the economic characteristics of thermal generation plant ensures that over time, aggregate income will be less than total cost. They concluded that not only is an energy-only market inherently unstable, but it does not have a 'defined equilibrium'.[20]

A key objective of this research is to demonstrate that the energy-only NEM fails to reach a stable equilibrium under competitive conditions. However, before introducing the static and dynamic partial equilibrium models used to quantify the extent of this instability, it is first necessary to make certain assumptions about the values of existing plant and new entrant plant. For the purposes of this research, the cost of all existing and new entrant plant in the NEM is assumed to reflect the form of three generation technologies:

- Super Critical pulverized fuel (SCpf) plant, which perform base load duties;
- Natural Gas Combined Cycle (NGCC) plant, which perform intermediate duties; and
- Open Cycle Gas Turbine (OCGT) plant, which perform peaking duties.

The cost assumptions for each technology are provided in Table 8. Note that the variable cost of production is calculated by multiplying the heat rate (kJ/MWh) by the unit fuel cost ($/GJ), then adding the variable operations and maintenance (O&M) cost. Unit clusters refers to the ideal plant configuration, given the assumptions surrounding Fixed O&M costs.

Table 8: New entrant generating plant costs

Generation technology	Capital cost ($/kW)	Unit size (MW)	Variable O&M ($/MWh)	Fixed O&M ($M pa)	Useful life (Yrs)	Heat rate (kJ/MWh)	Fuel cost ($/GJ)	Unit clusters (#)
SCpf	1,500	660	-	22.5	40	9,500	1.00	2
NGCC	1,050	375	2.50	4.5	30	7,100	3.25	1
OCGT	750	160	3.00	2.0	30	11,500	3.50	3
Cost of capital	11.00%							

[20] This of course assumes that new entry is considered desirable.

The average cost for a SCpf plant at a capacity factor of 90% per annum is around $34.50/MWh. NGCC plant has an average cost of around $42.25/MWh while the OCGT plant has an average cost of around $56.00/MWh. The cost data contained in Table 8 and the 2004/05 half-hourly load curves for Queensland, New South Wales, Victoria & South Australia, and an aggregated NEM load curve have been entered into a dynamic partial equilibrium model called Nemesys in order to determine the requirement for system reserves, the competitive spot price, and aggregate system cost (Appendix I provides an overview of the Nemesys Model). The key outcomes from the simulation model have been reproduced in Table 9.

Table 9: Power system scenario results using 2004/05 load data under conditions of an optimal plant mix and perfect competition amongst generators

Statistics with VoLL at:	$10,000.00	QLD	NSW	VIC/SA	ΣSTATES	NEM
Electricity Load						*unconstrained*
Peak demand	(MW)	8,232	12,884	10,986	29,403	29,403
Energy demand	(GWh)	49,440	74,432	62,414	186,287	186,662
Load factor	(%)	69%	66%	65%	72%	72%
Generating Plant						
Base plant	(MW)	6,600	9,900	7,920	24,420	24,420
Intermediate	(MW)	750	1,125	1,125	3,000	2,250
Peak plant	(MW)	2,720	4,160	3,840	10,720	7,200
Aggregate	(MW)	10,070	15,185	12,885	38,140	33,870
System Reliability						
Lost load	(%)	0.001%	0.002%	0.002%	0.002%	0.002%
System Reserve	(%)	22%	18%	17%	30%	15%
System Price/Cost						
Competitive spot price	($/MWh)	27.32	26.79	23.69	25.89	28.24
System unit cost	($/MWh)	41.37	41.33	41.35	41.35	38.96
Implied loss	($/MWh)	-14.05	-14.54	-17.66	-15.46	-10.72
Cost recovery	(%)	66%	65%	57%	63%	72%
Financial Results						
Asset Value (market)	($M)	12,727.5	19,151.3	15,941.3	47,820.0	44,392.5
Merchant revenue	($M)	1,350.6	2,102.6	1,746.6	5,199.8	5,814.3
Fuel costs	($M)	519.0	781.1	669.8	1,969.9	1,938.6
O&M costs	($M)	274.8	413.2	342.5	1,030.4	972.4
Capital costs	($M)	1,251.5	1,883.3	1,568.4	4,703.3	4,361.2
Implied loss	($M)	-694.7	-974.9	-834.1	-2,503.8	-1,457.8
Economic Returns (benchmark return = 11%)						
Base load SCpf plant	(%)	7.3%	7.7%	7.8%	7.6%	8.9%
Intermediate NGCC plant	(%)	8.6%	8.2%	7.6%	8.1%	8.9%
Peaking OCGT plant	(%)	6.5%	6.3%	5.3%	6.0%	7.9%
Aggregate plant stock	(%)	7.3%	7.5%	7.4%	7.4%	8.8%

There are five model-output columns in Table 9. The first three columns list the regional markets of Queensland, New South Wales, and the joint Victoria-South Australia region. The next column titled *'ΣStates'* is the arithmetic aggregate of the Queensland, New South Wales and Victoria-South Australia results. The final column titled *'NEM'* assumes an *unconstrained* transmission system – that is, it is a scenario that describes what the power system *should* look like were it not for the grossly inadequate transmission regulations that exist in the NEM. The most important result from Table 9 is that despite the perfectly optimal and cost minimizing plant stock assumed, a stable equilibrium could not be reached in any region.

The model outputs in Table 9 start with information regarding electricity load, viz. peak demand, energy demand and the system load factor.[21] Queensland has the highest regional load factor at 69%, with the aggregate NEM result highest at 72%, which is driven by the diversity of loads across Eastern Australia. Next in Table 9 is the Generating Plant statistics, which reflect the minimum cost solution given the load curve. Following this are the System Reliability statistics. The existing reliability panel criteria for the NEM is *no more than 1GWh lost for every 50,000 served*, which implies a loss of load probability benchmark of 0.002%. Consequently, the plant mix was driven down to the point just short of violating this constraint, thereby minimizing the amount, and therefore cost, of plant; and maximizing the number of 'tolerable blackouts', and therefore the number of $10,000/MWh price spike events.

The next segment of Table 9, System Price/Cost, provides an important quantitative analysis of the energy-only NEM under competitive market conditions. The results demonstrate that there is no definable equilibrium in any region. Note in every case that the competitive spot price is markedly lower than system unit cost. Cost-recovery ratio's range between 57% - 72%. In theory, the system with the highest load factor should exhibit the lowest cost. But the lack of interconnector capacity can distort this outcome.[22] In fact quite unexpectedly, each of the regions has an average cost of around $41.35/MWh.[23] The reason for this is that the differing reserve plant margin requirement in each region has largely offset the impact of system load factor. The unconstrained NEM on the other hand has the highest system load factor, the lowest reserve requirement, and consequently, the lowest system unit cost by a considerable margin. But despite the 'ideal' *unconstrained NEM* market, generators still only recoup 72% of fair costs. This cost recovery ratio relies critically on VoLL at $10,000/MWh. If, for example, VoLL was reduced to $5,000/MWh, the cost recovery ratio in the unconstrained NEM would reduce from 72% to 63%. The individual region results reduce by a similar margin.

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[21] System load factor is a measure of the 'peakiness' of aggregate demand, and is calculated as [Energy Demand MWh ÷ [Peak Load MW x 8760)]. The closer the result is to unity, the more favourable the load factor is, implying a high base load relative to peak load.

[22] Note the $3.4 billion difference in assets between the ΣState column and the NEM column – which is driven by the difference in transmission, albeit based on generator data contained in Table 8. The carrying cost amounts to $342.1 million per annum. Booth (2004) previously examined the marginal increase in transmission capacity and costs required to achieve a constraint-free NEM power system. His studies concluded that 3,350MW of interconnector capacity at a capital cost of $2.4 billion, or $1.30/MWh, would enable the free flow of power around the NEM between now and 2015. Transmission investment in the NEM has been severely constrained since inception. Initially the regulator was convinced that by implementing Nodal Pricing, merchant generators would voluntarily invest in the requisite transmission capacity to alleviate constraints. Clearly, this was not the case, as the New Zealand experiment so elegantly demonstrated: *The reforms decreed that the owner and operator of the transmission system was not obliged to provide the transmission capacity needed to avoid transmission constraints. The expectation was that the players in the market would pay the transmission operator to reinforce the system. Not surprisingly, [after nearly 10 years of deregulation] this has not happened and New Zealand now has a transmission system which often limits generation… (Leyland, 2003, p.21).* More recently, changes to the way in which transmission interconnects are assessed (i.e. the Net Benefit Test) has been improved. But fundamentally, the Net Benefit Test still fails to quantify the substantial gains in efficiency that would naturally arise as a result of enhanced inter-regional competition amongst generators.

[23] Note that this condition only holds when common technologies and technology costs are assumed. In reality, the Queensland region is endowed with vast deposits of low-cost thermal (black) coals, and more recently, vast reserves of low-cost coal seam methane. The combined effect is likely to subtract around $3.00/MWh from the average cost statistic. Victoria on the other hand is unlikely to develop coal-fired SCpf plant due to the CO_2 intensity of brown coal and the risk of carbon pricing.

The Financial Results segment of Table 9 provides a consolidated Profit & Loss Statement for the total generation portfolio by region. The losses reflect the gaps in the cost recovery ratio, and place a quantitative figure on the extent of the problem associated with energy-only markets. To be sure, the Merchant Revenue calculations in Table 9 were calculated by reference to energy and spot price. That is, there is no hedge contract income included in the determination of revenues. Prima facie, one may argue that the absence of hedge revenues constitutes an inherent floor in the analysis. However, such a criticism is too convenient. The power system analysis undertaken in Table 9 assumes a competitive market and the existence of the least-cost, optimal mix of plant. In consequence, the modeled clearing prices reflect the natural economic result and therefore the expected fair value of hedge contracts.[24] Any deviation in hedge contract values (i.e. above or below the modeled spot price outcome) would violate the assumption of a competitive market, would ignore the ability to arbitrage, and perhaps most significantly, would assume that electricity retailing is uncompetitive and that all retailers are inherently incompetent in trading forward hedge contracts. Yet even allowing these principles to be violated at the extreme, and assuming the existence of a $5.00/MWh spot-swap spread, such margins pale into insignificance by comparison to the $14.00 - $17.00 losses incurred by generators in Table 9.

The Economic Returns by generator class and by region provided in Table 9 confirm that against the benchmark result of 11%, no technology makes an adequate return, and peaking plant incurs the greatest losses. This, in large part, explains the ever deteriorating deficit in peaking plant.

In any event, the results in Table 9 confirm that there is no evidence that the NEM, or any of its regions, have a tractable equilibrium given a reliability constraint. Note that when the NEM transmission system is 'constrained' (i.e. column 4 results), a competitive energy-only gross pool with an optimal plant mix will incur financial losses of around $2.5 billion per annum. As Bidwell and Henney (2004, p.22) explain, for an energy-only market to be remunerative to all plant whilst remaining in a state of competitiveness, the power system would need to be *"near the edge of collapse"*. In a sensitivity study, the Nemesys Model indicated that for New South Wales generators to balance their books, blackouts would need to exceed the Reliability Panel's 0.002% threshold by 2½ times, which naturally occurs when system reserves are driven down from 18% to 13%.

9. Incorporating capacity payments in the NEM gross pool: a tractable equilibrium

Since the energy-only gross pool is inherently unstable with no definable equilibrium, why has a meltdown not yet occurred in the NEM, and what is the remedy? A meltdown has not occurred because the power system has, as noted earlier, thrived on its 'monopoly plant stock' provided to it at inception in 1998, and has been aided by a *billion dollar chicken* competition in Queensland. High demand (PoE10) has also been avoided on working weekdays. The combination of these factors has until now shielded the demand-side from a number of otherwise inevitable perils.[25] But the last of the monopoly oversupply in the state of NSW is about to be exhausted in aggregate. As for the remedy, it can be found in the academic literature of electricity supply industry economists from the late-1940s and late-1960s.

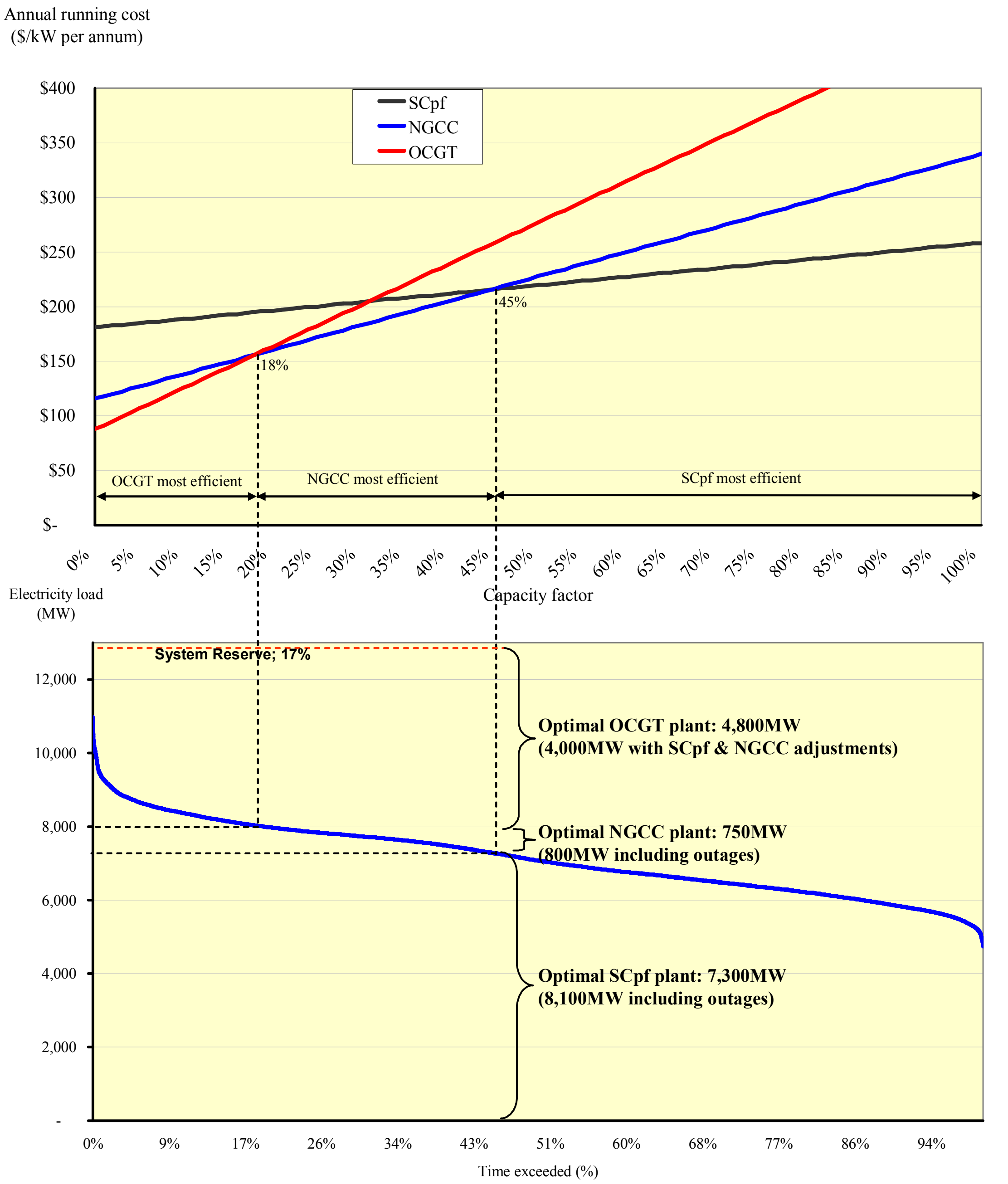
The underlying problem described in this paper, that is, the lack of a stable equilibrium under marginal cost pricing, was solved by former *Electricite de France* Chief Economist, Marcel Boiteux in 1949. Boiteux's (1949) concept was that an efficient power system would involve

[24] These concepts merely reflect Fama's (1970) generally accepted 'Efficient Market Hypothesis'. The implication here is that electricity markets can be categorised as *semi-strong form efficient* as per the categories defined by Roberts (1967). For further details, see Brealey & Myers (1996), *Principles of Corporate Finance*, McGraw-Hill, Sydney.

[25] The peaking plant crisis that occurred in Victoria during 2000/01 notwithstanding.

determining a marginal price to be paid to all dispatched plant, based on the cost of the load-following unit in each period, and added to this was the marginal capacity cost (i.e. the carrying cost of a new peaking plant), which was paid during peak periods. His calculations determined that all plant would *just* recover all of their reasonable costs. Given the absence of today's computing technology, and the complexity of the power system in France even at that time, this was a remarkable finding. Adding substantially to the Boiteux (1949) constructs was former Chief Economist of the Central Electricity Generating Board of England &Wales Tom Berrie's (1967a, 1967b, and 1967c) works, which is illustrated in Figure 1.

Figure 1: Partial equilibrium model of a power system: marginal running cost curves and system load duration curve for Victoria-South Australia with a 17% reserve plant margin



Berrie's (1967b) static partial equilibrium model outlined in Figure 1establishes the optimal plant mix for a given power system, by transposing plant costs in light of production duties to create *annual running cost curves*. Annual running cost curves specifically take into account power station costs on a capacity utilisation basis, thus capturing the rich blend of fixed and variable costs associated with the different generation technologies deployed in a power system, the optimum combination of which will minimize the overall cost of supply. This partial equilibrium framework illustrated in Figure 1 uses the cost data from Table 8 (top graph) and a load duration curve for the Victoria-South Australian region in 2004/05 (bottom graph).

In the top graph, the y-axis intercept marks the annual fixed cost of plant, while the slope of the cost curve signifies the variable running cost of the plant. Note from the top graph in Figure 1 that the lowest cost generation plant option for production duties up to 18% capacity factor is the OCGT. Production duties above 45% capacity factor are best served by SCpf plant. Intermediate production, which lies between these bounds, is best served by NGCC plant. When the intercept points of 18% and 45% are transposed down to the bottom graph in Figure 1 (i.e. the power system load duration curve), the optimal mix of plant can be defined. When initially transposed, there is an implicit assumption that plant is operating at 100% availability. Consequently, in order to minimise system cost, these equilibrium points need to be adjusted for expected outage rates. Thus, in Figure 1, the optimal mix of base plant at an assumed 100% availability factor is around 7300MW. After adjustments for outages, this result increases to 8100MW. Similarly intermediate plant is adjusted from 750MW to 800MW. With peaking plant, the reserve margin is added, and any increases in base and intermediate plant are deducted. Accordingly, with perfect plant availability the requirement for peaking plant is 4800MW and after adjustments is reduced to 4000MW. The combination of Boiteux (1949) and Berrie (1967b) thus ensures that productive (cost), allocative (price) and dynamic (expansion) efficiencies are maximised.

10. Dynamic partial equilibrium model results

Taking the Boiteux (1949) and Berrie (1967b) concepts and incorporating them in the Nemesys Model, a more sustainable result can be derived. The two primary differences that have been effected in the Nemesys Model are as follows:

1. A reduction in the level of VoLL from \$10,000/MWh to \$2,000/MWh; and

2. The addition of a 'capacity payment pool' equal to the carrying cost of an OCGT, payable to the optimal level of plant capacity (as opposed to the actual level of plant capacity).

The 'capacity payment pool' is therefore calculated for each region, and each region's pool is determined by multiplying the requisite 'optimal level' of generating capacity (MW) by the aggregate fixed cost of carrying an OCGT (i.e. \$10.70/MWh) over the entire 17520 half-hour periods in the year. The capacity payment pool is then paid to all generators at a unit rate (\$/MWh), based on plant availability in each half-hour period. The power system is otherwise identical, and the uniform, first-price mandatory gross pool auction mechanism that currently exists is assumed to continue with changes (1) and (2) above.

The results of this analysis are illustrated in Table 10 – which has the same five model-output columns as Table 9, with Electricity Load, Generating Plant and System Reliability outputs being identical. System unit cost and the aggregate costs in the Financial Results section are also identical. System prices and revenue differ very significantly, however. Because VoLL has been reduced from \$10000/MWh to just \$2000/MWh, average spot prices have reduced markedly. Taking the unconstrained NEM as an example in Table 10 below, the competitive spot price has reduced from \$28.24/MWh (Table 9) to just \$22.35/MWh. But the addition of the capacity payment pool, which is paid to available generators in each half-hour period, drives the average clearing price to \$38.94/MWh, just 2¢ short of the system unit cost of \$38.96/MWh. Under this market, retailers and generators would therefore hedge against two individual markets:

- The spot market, with expected flat swap prices of around \$22.00 - \$22.50/MWh in equilibrium (as opposed to the current \$35.00 - \$40.00/MWh); and

- The capacity market, with expected prices of around \$10.70/MWh per MW available.[26]

Table 10: Power system scenario results using 2004/05 load data under conditions of an optimal plant mix, perfect competition, capacity payments and VoLL of \$2,000.00/MWh

Statistics with VoLL at:	\$ 2,000.00	QLD	NSW	VIC/SA	ΣSTATES	NEM
Electricity Load						*unconstrained*
Peak demand	(MW)	8,232	12,884	10,986	29,403	29,403
Energy demand	(GWh)	49,440	74,432	62,414	186,287	186,662
Load factor	(%)	69%	66%	65%	72%	72%
Generating Plant						
Base plant	(MW)	6,600	9,900	7,920	24,420	24,420
Intermediate	(MW)	750	1,125	1,125	3,000	2,250
Peak plant	(MW)	2,720	4,160	3,840	10,720	7,200
Aggregate	(MW)	10,070	15,185	12,885	38,140	33,870
System Reliability						
Lost load	(%)	0.000%	0.002%	0.002%	0.001%	0.002%
System Reserve	(%)	22%	18%	17%	30%	15%
System Price/Cost						
Spot Price	(\$/MWh)	22.56	22.81	22.71	22.71	22.35
Capacity Price	(\$/MWh)	10.70	10.70	10.70	10.70	10.70
Spot + Capacity Price	(\$/MWh)	39.88	39.96	40.76	40.21	38.94
System unit cost	(\$/MWh)	41.37	41.37	41.35	41.36	38.96
Implied loss	(\$/MWh)	-1.49	-1.41	-0.59	-1.15	-0.02
Cost recovery	(%)	96%	97%	99%	97%	100%
Financial Results						
Asset Value (market)	(\$M)	12,727.5	19,151.3	15,941.3	47,820.0	44,392.5
Merchant revenue	(\$M)	1,115.5	1,684.2	1,447.0	4,246.8	4,391.9
Capacity Revenue	(\$M)	856.2	1,290.2	1,096.8	3,243.2	2,876.6
Total Revenue	(\$M)	1,971.7	2,974.4	2,543.8	7,490.0	7,268.5
Fuel costs	(\$M)	519.0	782.4	669.8	1,971.1	1,938.6
O&M costs	(\$M)	274.8	413.3	342.5	1,030.6	972.4
Capital costs	(\$M)	1,251.5	1,883.3	1,568.4	4,703.3	4,361.2
Implied loss	(\$M)	-73.5	-104.6	-36.9	-215.1	-3.7
Economic Returns (benchmark return = 11%)						
Base load SCpf plant	(%)	10.2%	10.3%	10.7%	10.4%	10.8%
Intermediate NGCC plant	(%)	11.5%	11.5%	11.2%	11.4%	11.6%
Peaking OCGT plant	(%)	12.5%	12.2%	11.6%	12.1%	12.1%
Aggregate plant stock	(%)	10.6%	10.6%	10.8%	10.7%	11.0%

Note that cost recovery is 100% or close thereto, and that the financial results balance (i.e. the \$3.7million implied loss being a rounding error in the context of a \$44.4 billion asset base). Similarly, the economic returns of plant are all roughly in line with benchmark, the difference in

[26] Bidwell (2005) presents a more robust solution to the form of the capacity payment market.

returns in this particular study being driven by the availability assumptions associated with gas-fired plant and coal plant and marginal deviations in the plant mix due to the indivisibility of plant capacity. These deviations notwithstanding, the results in each region are in line with the aggregate NEM outcome.

11. Dynamic behaviour of a gross pool market with capacity payments

It is useful to observe how such a market might behave under varying conditions of over- and under-supply. For a 'capacity payment pool' to work effectively, it must send the appropriate signals under deteriorating and over-heated investment conditions. To illustrate the behaviour of the 'capacity and energy' gross pool market, Table 11 produces model results for New South Wales under various over- and undersupply scenarios, holding electricity load constant.

Table 11: New South Wales scenarios of optimal supply, oversupply and undersupply

Statistics with VoLL at:	$ 2,000.00	Optimal plant supply	Base plant oversupply	Peak plant oversupply	Base plant undersupply	Peak plant undersupply
Aggregate						
Base plant	(MW)	9,900	11,220	9,900	9,240	9,900
Intermediate	(MW)	1,125	1,125	1,125	1,125	1,125
Peak plant	(MW)	4,160	4,160	5,440	4,160	3,680
Aggregate	(MW)	15,185	16,505	16,465	14,525	14,705
System Reliability						
Lost load	(%)	0.002%	0.000%	0.000%	0.006%	0.005%
System Reserve	(%)	18%	28%	28%	13%	14%
System Price/Cost						
Spot Price	($/MWh)	22.81	13.61	20.37	30.29	25.71
Capacity Price	($/MWh)	10.70	9.85	9.85	11.18	11.06
Spot + Capacity Price	($/MWh)	39.96	30.97	38.17	47.31	42.24
System unit cost	($/MWh)	41.37	43.75	42.87	40.55	40.80
Implied loss	($/MWh)	-1.41	-12.78	-4.70	6.77	1.44
Cost recovery	(%)	97%	71%	89%	117%	104%
Financial Results						
Asset Value (market)	($M)	19,151.3	21,131.3	20,111.3	18,161.3	18,791.3
Merchant revenue	($M)	1,684.2	1,014.5	1,551.9	2,230.7	1,853.1
Capacity Revenue	($M)	1,290.2	1,290.4	1,289.2	1,290.9	1,290.9
Total Revenue	($M)	2,974.4	2,304.9	2,841.1	3,521.6	3,144.0
Fuel costs	($M)	782.4	728.2	782.5	834.3	782.2
O&M costs	($M)	413.3	451.1	429.3	397.3	407.3
Capital costs	($M)	1,883.3	2,077.2	1,979.5	1,786.4	1,847.3
Implied loss	($M)	-104.6	-951.6	-350.2	503.6	107.2
Economic Returns (benchmark return = 11%)						
Base load SCpf plant	(%)	10.3%	7.4%	9.6%	12.6%	10.9%
Intermediate NGCC plant	(%)	11.5%	8.6%	10.4%	13.2%	12.5%
Peaking OCGT plant	(%)	12.2%	10.0%	10.3%	14.0%	14.0%
Aggregate plant stock	(%)	10.6%	7.8%	9.8%	12.8%	11.4%

The first column of results is reproduced from Table 10 and represents the optimal plant mix solution. The second results column involves a scenario whereby base plant has been deliberately overbuilt by 2 x 660MW units, with the reserve plant margin increasing from 18% to 28%. Holding the value of the 'capacity payment pool' constant, capacity payments are reduced from

\$10.70/MWh to \$9.85/MWh, with the resulting loss to generators being of the order of \$12.78/MWh. The peaking plant oversupply scenario (3rd column results) has a similar impact on reserve margin and therefore, the capacity payment. However, the loss incurred is substantially smaller (at \$4.70/MWh) because of healthier spot prices, as would be expected.

The final two columns deal with scenarios of undersupply. The first of these, where base plant is assumed to be undersupplied by 1 x 660MW unit, exhibits a sharp increase in system price. Note that in holding the capacity payment pool constant with a lower aggregate plant stock, the capacity price is lifted to \$11.18/MWh. Consequently, generators as a class earn a net return of 12.8% against the 11% benchmark, and the ability to enter profitably is clear. In the undersupplied peaking scenario, the results are less exaggerated with aggregate returns reaching 11.4%. But at a capacity payment of \$11.18/MWh, there is little doubt that peaking plant entry would occur.

In short, the presence of a capacity payment pool, divisible by the aggregate plant stock, enables a tractable, and definable equilibrium to be established without the need to exercise market power. And while a reliable market for reserve has been established, the extent of volatility has also been reduced substantially, as Table 12 notes, by a factor of more than 2½ times:

Table 12: Market price outcomes in oversupply and undersupply conditions

New South Wales region	Energy-only VoLL at \$10,000	Capacity + VoLL at \$2,000
Undersupplied (-660MW)	\$55.60/MWh	\$47.31/MWh
Oversupplied (+1320MW)	\$15.10/MWh	\$30.97/MWh
Volatility:	0.55	0.21

There is, however, a major ideological shift required by the industry, consumers and governments in order to progress from an energy-only market to a capacity and energy market. As Bidwell (2005, p.14) has noted, the concept of a capacity payment shifts a key variable from the market to a central authority:

> *…[Establishment of the capacity payment pool] requires an administratively determined vertical demand curve set at the point that will produce the desired reliability level…*

In simple terms, the level of reserve plant, which determines the capacity payment pool, needs to be set by some administrative body such as the Australian Energy Market Commission. In the scenarios outlined in Table 9, reserve plant margins were 'administratively determined' at a level whereby the reliability constraint would not be violated, based on the plant technologies deployed in Table 8.[27] This raises an issue as to whether such administration is necessary, or whether Adam Smith's 'invisible hand' is more appropriate. The contention in this research is that markets fail, and it is the role of government to fix them. And in the case at hand, the market failure relates to the absence of a definable equilibrium, given a reliability constraint.

Thus we return to the problem identified at the outset; by introducing a capacity market, State Governments can decide, in conjunction with the appropriate regulatory authority, upon the level of reliability that they require for their jurisdiction. The rationale for this type of policy intervention is elegantly described in Bidwell and Henney (2004, p.11). They note that while electricity supply is an essential service, its financial insignificance to domestic consumers means

[27] If the actual plant stock that exists in each region was used in the model, the reserve planning margins would no-doubt vary due to the greater diversity of unit capacities and technologies.

that they are not interested in responding to price signals per se, and in the event, liken reliability of electricity supply to a public good:

> *…it is necessary to have an external authority to act on the behalf of electricity consumers to determine an appropriate (joint) level of system-wide reliability and to ensure that there is an adequate level of system capacity. In this sense, power system reliability is somewhat like national defense. Each citizen cannot individually provide their own national defense. Nor can people have different levels of national defense. They must collectively decide what they want, and then appoint some authority to achieve it…*

This research has touched seldom and lightly on how a capacity market and the payment for capacity is best organized – and this therefore remains an issue for further research. Similarly, the manner in which a capacity payment is recovered from end-use consumers has not been addressed. In this paper, for simplicity, a flat $10.70/MWh payment was assumed for all available plant in each half-hour of the year when the plant stock was optimal. The unit price was assumed to increase or decrease according to the supply-demand balance relative to required reserves (i.e. the 'capacity payment pool' remains constant). But such a simplistic design would be open to manipulation by portfolio generators during periods of capacity scarcity. It is easy to imagine the withdrawal of plant capacity by large portfolio generators in order to drive price spikes in the spot market that lead to energy revenue gains that greatly exceed the short-run loss of capacity revenue. However, a rich body of research in this area does exist which provide policy avenues to overcome such abuses.

12. Sectoral implications

It is useful to review the likely implications arising from the introduction of capacity payments in the NEM. Certainly, while the economic arguments for introducing a capacity payments pool are bordering on overwhelming, such a substantial institutional change needs to be introduced sufficiently far enough ahead (e.g. five years) so as to allow market participants, investors and financiers to adjust to the new regime appropriately, and to minimize the potential claim of 'regulatory risk' in the NEM.

State governments should find such an institutional change highly appealing. The ability to administratively determine the requisite reserve plant margin for their region/electorate provides Government with the 'lever' that they have missed following the dismantling of the respective State Electricity Commissions. Importantly, it provides them with a lever and eliminates the need to retain ownership in generation or retail as an *electricity supply business of last resort.* Similarly, it removes the temptation to invest early in what are otherwise defined as uneconomic projects and evidence of political intervention.

Electricity retailers would benefit from reducing their exposure to the extreme business cycles that characterize energy-only, mandatory gross pool markets. As noted in Section 11, the level of market volatility will necessarily decline - if for no other reason than the reduction in the VoLL from $10,000 to $2,000. But more importantly, the requirement for, and implications of, being a *courageous retailer* soften considerably. In simple terms, the incidence of free-riding off the actions of a *courageous retailer* are almost eliminated.

The benefits to the generation sector are clear enough. The financial outcomes of the various portfolios of base, intermediate and peak varied at the margin. But these results reflected the model assumptions, specifically, base plant availabilities were assumed to be 2% lower than intermediate and peaking plant availabilities, and plant capacity was not perfectly divisible, and thus base plant in all cases were *'slightly'* overweight. Additionally, and perhaps appropriately, the returns accurately reflect the likely volatility of returns facing each class of generation. In reality, peaking plant (e.g. with take-or-pay fuel contracts) will continue to face higher risks due to uncertainties associated with weather and plant availabilities of the baseload fleet. Applied to the real world, as with any theoretical construct, there will be winners and losers of greater magnitudes due to variations in all the factors of production associated with power generation. For example, firms with special resource endowments (e.g. low cost fuel source), exceptional organizational efficiencies, or those who raised finance during low interest rate periods will fare better than the average. The reverse is also equally possible.

Equity investors would also benefit from a capacity and energy market. There exists a class of investors who have sought risky investments in the merchant power industry, no doubt with an expectation of earning returns higher than those on offer from the regulated electricity industry sector. But these higher risk-adjusted returns are almost certain to be 'illusory'. The reason for this is that first, as this research has already established, there is not a definable equilibrium in a competitive energy-only market with a reliability constraint. Second, this being the case, generators can only recover their costs when they exercise market power (i.e. bad VoLL) which then invariably becomes the subject of political intervention – as the generation sector discovered via the re-bidding inquiry during 2002. And third, if the wholesale market does clear at sufficient rates from load-shedding events (i.e. good VoLL), the system will be near the edge of collapse and State Governments will again intervene in any event.

Economic theory has long been relaxed with the proposition that customers do not willingly reveal their true preferences. And to that end, it is difficult to conclude whether such an institutional change will suit all customers. However, for the overwhelming majority of domestic and commercial consumers, we may postulate that they would prefer a competitive market that delivers a stable price path when the commodity in question is effectively an essential service. As a domestic consumer, this is most certainly the author's preference. Large industrials may have a preference for a boom-bust market, although the low level of demand-side management in the 40,000MW NEM provides some insight as to the extent of those customers truly interested in active market participation. Besides which, demand bidding would logically qualify for capacity payments, thus creating a revenue stream for astute consumers.

13. Summary

The purpose of this research was not to question the efficacy of the mandatory gross pool. The gross pool and the uniform first-price auction clearing mechanism remain sound theoretical constructs that help maximize static productive efficiency. What this research has questioned is whether an energy-only market can result in a stable equilibrium - be it a gross pool, a net pool, a regional market, a nodal market, with- or without FRC and VI. And the results of the quantitative analysis were clear enough – competitive energy-only markets do not have a stable or definable equilibrium. The presence of heavy fixed costs and compressed marginal cost curves ensures this result.

The historical analysis of the NEM power system presented in this paper found that the dynamic efficiency of the NEM has, in aggregate, improved since market start with oversupply reducing from 2700MW to 500MW over a seven-year history. But dynamic efficiency from a structural perspective has deteriorated substantially, with peaking plant shifting from an underweight position of 1600MW to underweight 3900MW over the same timeframe.

The analysis of the economics of peaking plant demonstrated that their profitability is especially random, and therefore hazardous, in the energy-only NEM. To compound the prospects for new peaking plant, simulations of the NEM regions under conditions of a competitive market with an optimal plant mix found them to be least profitable. The combination of these findings helps to explain the current lack of peaking plant within the aggregate plant mix. It also points to the fact that market failure is predictable.

Using a series of assumed plant cost and technology assumptions, modeling of the NEM power system and its regions under conditions of a competitive market and a reliability constraint found that there is no definable equilibrium, and as a result, a competitive energy-only market is inherently unstable. The power system would need to be near the edge of collapse before generators could recover their reasonable costs, thus violating the reliability constraint.

Finally was the analysis of the NEM after reducing VoLL to $2000 and introducing a capacity payment pool, payable at the rate equivalent to the annual carrying cost of an OCGT. Modeling results confirmed that a stable equilibrium could be achieved, with the aggregate plant stock in all regions earning at or close to benchmark returns.

In the absence of this important institutional change, the energy-only market will, with a grinding inevitability, continue to experience a cycle of capacity shortage, the exercise of generator market power, a sharp rise in market prices, consumer outrage and political intervention, a development frenzy 5-minutes after midnight, followed by a price recession until the next shortage. And like clockwork, it will predictably occur about six years later.

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