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Preface

This submission is based on an intimate knowledge of the Victorian Electricity Industry Restructuring, the close involvement with the establishment of the National Electricity Market (NEM) and over 10 years experience in electricity pricing both under a regulated environment and in the new competitive market.

Electricity Markets Research Institute (EMRI) undertakes research with primary focus on:

- Public benefit aspects of competitive electricity markets:
- Technical and market efficiency,
- Equity issues,
- Transition issues going from integrated utility in a monopoly market to competitive marketing.

A brief write-up of the work of EMRI and a short biography of the author are given in Appendix D.

1 Introduction

The National Electricity Reliability Panel (NERP) Final Report on the Review of VoLL makes a case for lifting the Price Cap in the National Electricity Market on the basis that currently there is insufficient incentive for attracting investment in new 'peaking plant' that will run for only 6 hours in the year. This submission attempts to assess the need to increase the Market Price Cap (VoLL) in the wider context of the competitive market framework envisaged in the National Electricity Market (NEM) design.

The submission will first look at the relevant principles of the NEM design that impact on the subject under discussion and highlight the public benefit aspects that need to be safeguarded. A short discussion then follows on the thorny question of how reserve capacity should be rewarded. Finally the submission will show why the NERP recommendations and the proposed Code Changes will lessen the public benefit as compared to the current arrangements.

It is unfortunate that the (NERP) report seems to confuse the issues by claiming that VoLL should be raised to $ 20,000 / MWh based on the higher incentives needed to ensure there will be future investment in peaking plant (and be available to provide reserve capacity). The real issue is whether the price cap in the NEM should be raised or not? The next question is whether the new price cap should be aligned with the Value of Lost Load (from a customer perspective) or should it be aligned to the correct incentive needed to ensure future investment in peaking plant (NERP assumption being that such plant will get to run only 6 hours in the year). The submission will present material to show that NERP has neither provided plausible evidence to show that Value of Lost Load from a customer perspective should be higher than its current accepted value of $ 5,000 / MWh, nor has NERP provided compelling evidence that there is a problem about future investment in new generating facilities, nor provided the evidence to establish that holding out special incentives for generation facilities that will run only 6 hours a year will increase the public benefit.

2 NEM Design Aspects Relevant to the Review of VoLL

2.1 Competitive Market

Section 1.3 (b)(1) of the Code gives the Market Objectives as "the market should be **competitive**".

The Commission in its Determination of 8 October 1999 said "The Commission notes the argument that the NEM has been established primarily for the benefit of end users, and indeed agrees that this is the underlying rationale for the reforms undertaken in the ESI". A logical conclusion then would be that an important part of the Public Benefit test should be to evaluate the impact on end-user prices, both short-term and long-term.

2.2 Demand Side is a Price Taker in the NEM important point to bear in mind is that the NEM is essentially a suppliers market in that the 'demand' side has no effective role in the price setting process. The market price is the simple average of six 5-minute dispatch interval prices. The price setting process is such that virtually all end-use customers are unable to respond in time to either influence market price or to alter consumption to avoid having to pay high pool prices.

ABARE report claims that electricity demand is relatively unresponsive to electricity price changes, a fact not substantiated by other studies or experience in the industry. Australian Gas Association Research Paper No 3 estimates the following long run price elasticities for electricity:

Residential	-0.24
Industrial	-0.19
Commercial	--0.27

As most instances of electricity price increases have been relatively small and prices have tended to move only upwards, it is not possible to be prescriptive about these matters but sufficient to say that there was a significant dip in the sales growth figures when Victorian Residential customers had a 10% price increase from 1 November 1992.

Because electricity cannot be economically stored the wholesale price (NEM) flows directly through to the retail price. If end-use customers have no opportunity to decide whether to purchase or not when prices exceed their 'willingness to pay' criteria, then that market would not be a truly competitive market. If a 10% price increase in November 1992 led to a significant reduction in energy sales growth what would be the response to a 10,000% price (to $5,000/MWh) increase? Retail price packaging that offer flat energy rates do impose on the customer the impact of these high price spikes

- as an increase in average price (due to the upward bias of the price spikes) and
- as an extra premium to manage price volatility (risk).

It is precisely for this reason that the Offer (and the current Ofgem) in the UK pursued with vigour the rise in the incidence of "unrepresentative price spikes" in the UK pool. This was the reason that the UK Pool design included a Price Cap equal to the Value of Lost Load (VoLL) as a surrogate to the lack of a demand side bid, being repeated in the NEM as well. In the UK, the Pool price is determined a day ahead and gives customers the opportunity to reduce consumption if they think price is higher than their 'willingness to pay', a facility not possible in the NEM with five minute ahead dispatch pricing.

Recommendation: Given that in the current NEM design (gross pool) Demand Side is a captive buyer, any measure that favour higher prices must be thoroughly scrutinised.

2.3 Competition on the Supply Side is essential as it is the next Best Solution

Given the above imperfection in the market design, the next best solution is to have effective competition on the supply side. It is the Electricity Markets Research Institute contention that the 5 minute dispatch pricing interval is a major impediment to effective competition on the supply side. An analysis of high price events in the NEM clearly demonstrate that the great majority of instances when pool price was above $100 / MWh (say) was due to time needed to bring plant on line or due to time constraints for ramping-up plant already running on-line. For example, vast majority of plant in the NEM are coal fired steam turbines with ramp-up rates around 10 MW per minute. While ramp-up rates for gas turbines are two to three times the rate for coal fired plant, most gas turbine plant need 6 to 12 hours to come on stream. This means that the small number of major hydro stations and fast start gas turbines have a near monopoly status when responding to sudden changes in load requirement:

- Loss of a generator

Loss of a transmission line

- Significant error in the NEMMCO demand forecast (usually due to sudden weather changes)
- Rare instances of unexpected load switching.

In VicPool, the practice was to require generators maintain 5% of their bid dispatch capability available for call-up under governor control – very fast response. In NEM this was reduced to 2% (some generators even being exempted from this requirement) on the premise that it was more economical to have the reserve requirement from a generator (s) lower on the merit order rather than require all generators to keep 5% capacity available for this purpose. The only problem is whereas previously on-line generators could have given a combined output increase of around 750 MW easily within two minutes, this has now dropped to around 300 MW or less due to ramp rate constraints of those generators now filling the reserve requirement. Considering the small marginal cost differences between on-line generators and those currently filling the reserve requirement and the very large price spikes that the change enables, the claimed economic justification for the change in the governor control requirement needs to be tested.

One possibility to ameliorate this problem would have been to pay the generators their bid price and the quantity weighted average generator price for that period being declared the Market Average Price. The generators would then have to be more economically responsible for their bids and the whole market would not be held to ramson by those who have residual market power. According to the current NEM design, high prices are more an exercise of market power to get higher returns than a signal for new investment.

Interestingly, NERP Issues paper of 13 May 1999 had this to say "In the Argentina (model) significant improvement in the efficiency of the industry has been achieved with a centrally determined wholesale price and competition amongst generators for dispatch on the basis of offered prices"

Another option worth considering is to treat the fast response requirement as an Ancillary Service, an option mentioned by the Commission in its Draft Determination of 8 October 1999.

2.4 Price Spikes and the Public Benefit

Prior to restructuring, generators were loaded according to their position on the marginal cost merit order, starting with those who had the lowest marginal cost. This provided the most economically efficient outcome. The UK Pool arrangements (which was followed in Victoria) were premised on the expectation that generators would normally bid at their marginal cost. Further, the UK system is a much larger multiple of the biggest generator unit on the system than in Victoria (and in the NEM) and therefore individual units do not command residual demand. Where bid prices deviate from the units marginal cost, the economic efficiency suffer. If the bid price is many times the unit's marginal cost and do set the Pool Price, the inefficiency is magnified many times.

It is heartening to note the Commissions interest in developments concerning other overseas electricity pool markets. We wish to bring to the Commissions attention how seriously the UK Regulator (Ofgem) views the incidence of high price spikes in the UK Pool. In the 1999 July discussion paper, Ofgem expressed concern that the recent Pool prices did not reflect underlying supply/demand fundamentals and were not representative of the prices that would be seen in an orderly market. Generator claims that high price spikes were required to compensate for periods of low prices were not accepted by Ofgen "in a competitive market, it would not be possible to raise prices to compensate for perceived lower prices in earlier periods". Considering the significance of Ofgen's findings on that instance vis a vis NERP claims that NEM needs still higher price spikes, we have attached as Appendix A, some key extracts from the Ofgem Decision Document of October 1999 entitled "Rises in Pool Prices in July" for the benefit of the Commission and other interested parties.

This concern on the impact of bidding behavior on market efficiency is also being followed up in the Californian market as evidenced by a recent article by Frank Wolak (Chairman of the ISO Market Surveillance

mmittee), et al, titled "Diagnosing Market Power in California's Deregulated Wholesale Electricity ..arket", where the authors had this to say:
"In the first year of the deregulated California electricity market a number of issues have arisen that relate to the competitiveness of the wholesale electricity market in the state. There have been lively debates over the need for price caps in the California Power Exchange (PX) day-ahead market and the California Independent System Operator's (ISO) real-time energy and ancillary services markets. These debates have raised the question of whether the high prices that have been observed at times are a result of scarcity of generating capacity during peak demand periods in a competitive market or are the outcome of the attempts of some market participants to exercise market power".

"The questions raised in these discussions are central to judgments about the degree to which the California wholesale electricity market is currently able to operate efficiently without intervention from the PX, ISO, or government regulatory institutions".

The authors examined the degree of competition in the California wholesale electricity market during June-November 1998 by comparing the market prices with estimates of the prices that would have resulted if all firms were price takers. "We found that there were significant departures from competitive pricing and that it was most pronounced during the highest demand periods. Overall, this raised the cost of power purchases by about 22% above the competitive level". Their conclusion was "the prices observed cannot be attributed to competitive peak-load pricing". The Abstract of that article is included as Appendix B.

A change in the price cap is likely to increases the size of price spikes (as opposed to the frequency of price spikes) and will produce two outcomes:

- The average price will increase (because almost all the price spikes will be positive)
- The cost to manage the higher price risk (eg the hedge costs) will increase

Both outcomes will be detrimental to Public Benefit and NERP has not shown that the benefits from increasing the price cap would outweigh these detriments to Public Benefit

Recommendation: NERP should be required to do a cost benefit analysis of the proposed change in the value of VoLL.

2.5 Reliability and Reserve Requirements

Clause 8.8 of the Code requires the National Electricity Reliability Panel (NERP) to determine the Reliability standard to be followed in the NEM. In June 1998, NERP determined that the reliability standard in the wholesale market (NEM) should be set at a maximum of 0.002% of regional un-served demand in any region. The NERP considered number of factors, some of which being:

- End-use customer reliability varies considerably across the market and is determined by a number of factors, in particular distribution network performance;
- The market has been designed around a consistent price across the market, including the price cap (VoLL);
- The Panel notes that involuntary load shedding in Queensland in early 1998 resulted from the forced shutdown of four major generating units at times of very high demand. Involuntary load shedding under these conditions is virtually inevitable in all power systems, as reserve to guard against it is prohibitively expensive. Events in Auckland New Zealand in early 1998 were related to major network failures not a failure of the New Zealand energy market to attract sufficient generating / demand side capacity which are addressed by these standards"

The reliability standard determined by the NERP was very close to the planning level of reliability historically applied in the jurisdictions. The proposed levels were very similar in New South Wales and South Australia, while it resulted in a higher level (ie a more reliable position) in Victoria. Based on the reliability standard so determined NEMMCO has derived an intervention threshold capacity reserve (above a demand forecast with 10% probability of being exceeded) subject to a minimum equal to the size of the largest single supply source in the region. As the NEM operates as an Energy Only market, there is no specific provision to pay for this reserve requirement. This where the wheels start to fall off this part of the NEM design. The problem arises when special incentives are devised to overcome this design deficiency with regard to paying for reserve.

Assuming that for a given situation (happening only once an year, ie in every 8760 hours) it is necessary to shed 5% of regional load, then that involuntary load shedding period can extend up to 3.5 hours and still be 'thin the reliability standard. If it is necessary to drop 10% of the load, then the allowable duration ⌄ecomes smaller – 1.75 hours. The 6 hours quoted by NERP would imply the shedding of around 3% of the regional load. So far so good, all sounds reasonable. What is not defensible is the assumption that an investment proposal will get up on the basis that the power station under consideration (meant only to be kept as reserve except at times of VoLL) will run only for 6 hours in the year:

- Will there be a policeman standing at the door of the power station to check whether the plant operates at any time other than during times of involuntary load shedding?
- Will the station owner be required under its licence to pay back to the market any revenues it gets from writing all kinds of exotic financial derivatives?

Considering the large number of gas turbine power stations built (quite a number in the UK) within the last 5 years, gas turbine economics have changed dramatically. Lead time, purchase price and cost of capital have all come down, efficiency has improved and many of these gas turbines installed in the UK now run as base load with coal fired stations being delegated to run as midrange plant. If VoLL is increased to $20,000 per MWh purely on the basis of providing incentives to new investment in peaking plant, not only these new investors but also all existing generation owners will be laughing all the way to the bank.

2.6 Reliability Level Should be based on Customer Expectations

As an electricity pricing practitioner I have been a keen follower of how customers value reliability. In the SECV days we avidly followed studies by Electric Power Research Institute (EPRI) on what was then called 'Outage Costs'. I was fortunate enough to have personal contact with electricity pricing personnel from leading USA utilities doing pioneering work in this field. While I was working for Eastern Energy I coordinated the provision of customer consumption statistics to Dr Khan from the Monash University when he was doing the original study for ESAA and later when was extending his study to meet VPX requirements. It is unfortunate that due to his untimely death Dr Khan was not able to meet with his many critics and assist in the resolution of many outstanding issues connected with that study. We owe a lot to his pioneering work on the subject here in Australia.

It is also very unfortunate that NECA and the NERP have proceeded so far with setting Reliability Standards and are now re-setting VoLL without a proper study to determine and incorporate the customers expectations on the subject. The Commission in its determination of 8 October 1999, was right to draw attention to this lack of effective consultation on key NEM aspects "The Commission notes the argument that the NEM has been established primarily for the benefit of end users, and indeed agrees that this is the underlying rationale for the reforms undertaken in the ESI. It is therefore of some concern that end users consider that they have no formal process for input into the very arrangements established for their benefit. In particular the Commission is concerned that many of the reviews of aspects of the NEC have taken place and are likely to take place without the benefit of end users' perspective, or only with limited input from end users".

Over the years, large number of researchers have followed many different ways to derive outage cost or VoLL. Some methods give better results than others and what methodology is appropriate will depend also on how much money you are going to spend on the exercise and what you intend to do with the results. Discerning Market Researchers know that what the customer says has to be taken with a pinch of salt (so to say). One Pricing Manager from Niagara Mohawk told me the story how they found to their embarrassment that the number of customers who during the survey said they were prepared to pay a particular price did not all put their money down when the time come to pay up. Some surveys use proxies, others follow a direct cost approach, while yet others follow contingent valuation techniques. There are also the standard survey bias that needs to be tackled, eg bias towards the 'willingness to accept' as against the 'willingness to pay', not to forget the 'status quo bias'.

I have compared the base data derived in the Monash study with findings from other studies and is inclined to accept them as a suitable starting point. To give a flavour of what is involved I like to quote from two studies:

- Ontario Hydro in 1980 for a 20 minute power outage:

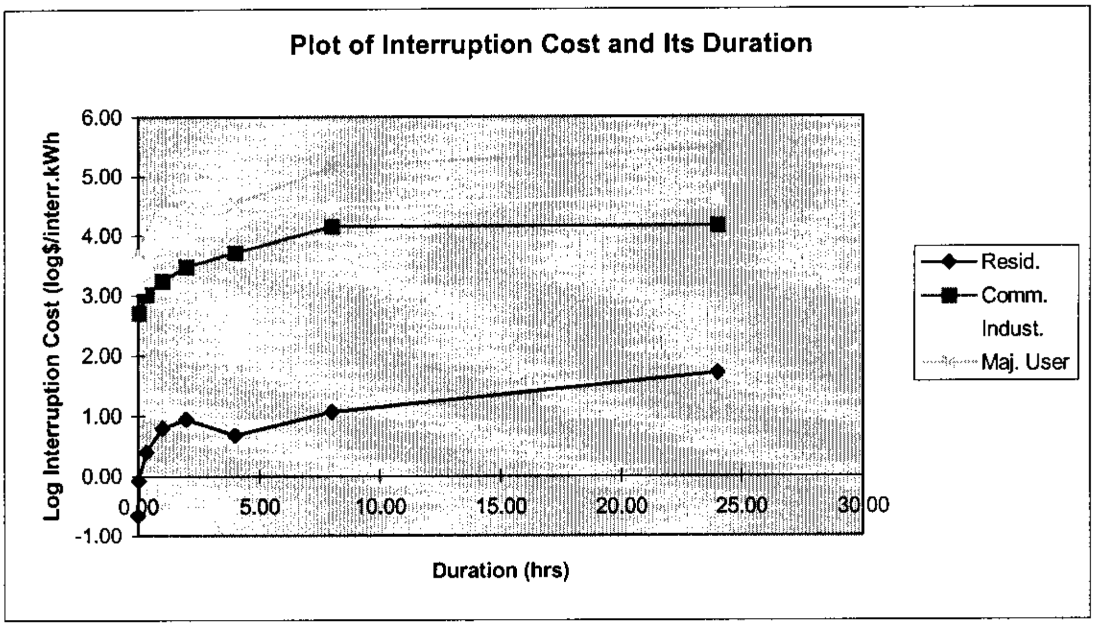
Residential customers	US $ 0.04 / kW
Large Industries	US $ 2.46 /kW
Office Buildings	US $ 6.73 /kW

- Niagara Mohawk (1992) for a a range of durations and different times of the day / year

		Winter	Summer
Residential cost	US $ / kWh	2.00 to 9.50	1.50 to 6.75
Industrial cost	US $ / kWh	2.75 to 16.50	2.00 to 13.50

The fatal flaw in the Monash study is the aggregation methodology:

- Outage cost has two components, one due to the incidence of the outage (which could be a momentary dip that shuts the computers down), and the other due to the time duration of the outage (or the quantum of lost load). The attached graph of the raw results for the different customer groups taken from the Monash study illustrate this aspect very starkly.



To facilitate the aggregation of the survey values Dr Khan assumes that VoLL is a function of duration of interruption only (Equation 12.2 in the Report to VPX). This assumption is at odds with the significantly high constant that should have been there in such an equation. When the VoLL results are then transposed to the 'Energy Only' NEM, the incorrect variablising of the constant (intercept) value causes a major error in the end results.

b) The high outage costs for the commercial customers are due to the high incidence of computer use and the large number of high rise buildings that require stand-by electricity generation facilities. In practice most of the big and small computer users nowadays have installed Un-interrupted power supplies (UPS). Also quite a number of the high rise office buildings nowadays have their own stand-by supply system. Considering these customers have already incurred such costs, to expect them to pay the electricity supplier again for the equivalent duplication of the same service, would amount to double dipping.

EMRI is of the view that properly evaluated Value of Lost Load would be in the range $ 5,000 to $ 10,000 and definitely not as high as $ 22,000 to 28,000 / MWh derived in the Monash study.

The NERP report makes reference to the priority order for load shedding, which usually specify that Residential customer load gets shed first, eg the residential suburbs of Adelaide were the only load shed during the supply shortage in the South Australia on the 4 February 1999. This priority order is sensible in that by this means public benefit is least affected. SECV maintained a very good record of avoiding involuntary load shedding by resorting to public appeals for voluntary load reductions specially from residential customers. It is worthwhile to further pursue the statement in the NERP report "Whilst VoLL is primarily the market price cap it is also used to set the market price on any occasion involuntary load shedding is required (?). The most economically efficient price is the highest customer valuation of load shed on an involuntary basis, assuming shedding priority reflects those valuations". If it is established that residential customer load comes first in the priority order for load shedding in all the

Jurisdictions and that all previous cases of load shedding was confined to only residential customers, there is no justification in the current proposal to raise VoLL to $ 20,000 / MWh.

2. 7 Need for a Price Cap

It is interesting to look back on the November 1996 submission by NEMMCO and NECA to the ACCC for authorisation of the Code. The following quotes from the NERP Issues Paper are worth noting:
"It argued there were inflexibilities on both sides of the market. Many generators had start-up and ramp-rate constraints. Few purchases had the ability to control the amount of electricity they were taking from the wholesale market at any time".
"It was suggested that VoLL is a simplified surrogate for the wide range of values that customers affected by load shedding would place on their lost load".
"The submission noted that the proposed value for VoLL of $ 5,000 / MWh was intended to strike a balance between these two conflicting needs at the start of the market. The chosen value was consistent with that currently used in the Emgland and Wales market".

In fact the Issues Paper reiterated these sentiments again :
"Many generators take 12 hours or more to start, and hence may be unable TO RESPOND TO HIGH SPOT PRICES UNLESS GIVEN SOME NOTICE. On the customer side, it may not be practicable or cost effective to modify a factory's production schedule at short notice. Some forecasting tools (pre-dispatch and PASA) are provided to predict when high (and low) spot prices are likely to occur and thus help participants manage their inflexibilities. But the accuracy of the forecasts may be less than ideal.."

Also "There is no evidence that demand side responses will consistently clear the market at lower prices than a supply side response, therefore it appears that VoLL needs to be at least the level at which marginal supply side response is possible, ie $10,000 per MWh, if the market is to have a reasonable prospect of consistently clearing voluntarily in the longer term".

And " The table indicates that an implied level of VoLL of at least $10,000 /MWh is necessary to provide sufficient revenue for such a plant (s6.2.1)".

Most of these statements are still true and there is no ambiguity on the need for maintaining the price cap. Sadly the NERP Report has not provided conclusive evidence why the price cap should be increased. There was mention of the Monash University study that derived a single aggregate representative value of $25,000/MWh and but the Report went on to say "The Panel's issues paper also rejected the use of a single aggregate value broadly for the reasons submitted by Egon.".

Except a passing comment that "VPX notes that a valuation of approximately $20,000 /MWh would be needed to ensure a continuation of historical levels of transmission design reliability in Victoria", (a circular reference in that this comment was referring to figures given in the Issues Paper and was not based on VPX's own independent evaluation) NERP has failed to justify why it chose Issues Paper Option 3 (the extreme value) instead of the Option 2 that NERP seemed to favour previously: "It is therefore most likely that a one-off episode of high spot prices could threaten the integrity of the market unless the value of VoLL was set well in excess of the levels at which voluntary clearing was anticipated and hence well in excess of the level market participants will be prepared for, say, $20,000/MWh". The inconclusive nature of NERP assertions is evident in the arguments for final VoLL price in Option 2 ($10,000) "where consistent voluntary clearing can be anticipated" Vs Option 3 ($20,000) "where voluntary clearing is likely to occur". What is the better prospect "can be anticipated" or "likely to occur"? Or should we toss a coin?

It is interesting to compare how the NERP methodology compares with the work of the Californian ISO Market Surveillance Committee, of which Dr Frank Wolak is the Chairman. It is noteworthy that the price cap in the Californian market is only $ 750/MW which they say will be kept until the end of Summer 2000.

For the benefit of the Commission and other interested parties, I have attached the summary and the main recommendations of the ISO Market Surveillance Committee **"Report on Redesign of California Real-Time Energy and Ancillary Services Markets"** as Appendix C

Recommendation: Given that the recommended increase in VoLL is tantamount to a provision which have the purpose, effect or likely effect of fixing, controlling or maintaining prices and no evaluation

's been provide to demonstrate that the benefit would outweigh the detriment to the public, the Commission should disallow the requested increase in the VoLL value.

3 Options Impacting on Future Requirements of Reserve Capacity

3.1 Open Cycle Gas Turbine Option

NERP Report recommendation to increase the value of VoLL to $20,000 /MWh is based on the premise that such a value is required to justify investment in a peak plant - more specifically an Open Cycle Gas Turbine that will run for 6 hours in the year. Such a recommendation based on a particular technology is contrary to the Code provision on technology neutrality.

The NERP Report acknowledges that average prices in Queensland and South Australia do justify additional base load or mid-range plant, and that already there are plans for such plant. It is a bit thick to imply that because they are planned by Government instrumentalities, normal economic evaluation has not being followed. If these plant will provide the required level of Reserve Capacity, does it matter whether they are base load plant, mid-range plant or peaking plant. The UK experience has shown that such differentiation is now getting blurred.

3.2 Overhang of Other Lower Cost Options

In the South Eastern Inter-connected system there is so much excess capacity that some plant have been moth-balled until demand grows further. With the already mooted connections to Queensland due shortly, greenfield investment run the risk of triggering the early reopening of the currently moth-balled plant. Presence of moth-balled plant indicate that there is no real shortage of reserve capacity but only very short-term deficiencies due to operational exigencies.

As indicated in number of submissions to the NERP, there are also lower cost network options to meet projected reserve shortages in particular regions as mentioned in the VPX 1999 Annual Planning Review. To optimise public benefit, these options should be promoted in preference to higher cost options like Open Cycle Gas Turbines

There is active consideration being given to retro-fit or add new gas turbine plant at existing generating stations in Victoria, which will greatly reduce the initial capital cost compared to a greenfields Open Cycle Gas Turbine plant. It would be in their self interest to hold-off announcing such development proposals on the expectation that more favourable concessions are forthcoming.

3.3 Other Developments Impacting on Future Reserve Capacity

The NERP Report has failed to consider two developments that has the potential to significantly add to the reserve levels:
- does not take into account Basslink for which expressions of interest has already been sought.
- does not take into account the 2% increase in generating capacity from new renewables mandated for 2010, which would have a significant peaking component due to potential for solar PV panels in remote locations.

4 Impact of NERP Recommendations on the Supply Side

4.1 Peaking Plant given special consideration

As discussed previously, the Code specifically prohibit special treatment for particular technologies. The boundary between the different types of generating plant are getting blurred and such special treatment will favour the supply side at the expense of the demand side.

4.2 Flow on benefits to supply side of the energy market

As discussed in the Supply side assessment section of the NERP Report, "the value of energy traded in Queensland in the 6 months in the top 10% of demand was approximately 46% of the revenue requirement for a peaking supply side investment equal in size to 10% of the demand". But it was acknowledged that the average price in Queensland for the 6 months was sufficient to ensure viability of base or mid merit plant.

:reasing the price cap to provide further benefits to the peaking plant type investment would mean the ʋase or mid merit plant would be able to earn super normal profits. Such super normal profit has to come from the demand side of the market and would be detrimental to the public benefit.
The higher price cap will not only mean higher revenues from the energy market but also higher prices (and profits) from hedge contracts as well. There is no economic justification for such super profits and again enabling such an opportunity would be against the public benefit.

In the future there would be more and more arbitraging opportunities between Electricity and Gas Markets. Opportunity for super profits in the electricity market would eventually have an impact on the gas market also, give undue advantage to those companies having a stake in both markets compared to those operating only in the gas market.

5 Impact of NERP Recommendations on the Network Businesses

According to the VPX Annual Planning Review, for a given set of generation and network conditions the transmission capacity can be defined by the maximum demand that can be supported. If higher demands occur for a particular set of conditions then energy would be at risk. By increasing the transmission capacity, the energy at risk can be reduced. Considering the needle type peaks that happen due to extreme summer temperatures, incremental capacity increases lead to smaller and smaller step reductions in energy at risk. Optimum investment in the network is then determined by reference to the Value of Lost Load (VoLL) value times energy at risk. As the recent Vencorp paper on 'Future Electricity Transmission Network Reactive Support" indicated, as the VoLL price is increased Vencorp will be re-evaluating required level of network capacity so as to maintain consistency with design parameters, which means higher investment in the network.

Considering any increased Value of Lost Load (VoLL) translates to increased investment in Networks, an increase in VoLL simply to provide an incentive to peak load generators with no additional benefit to end-users would result in a 'gold plating' exercise leading to a reduction in public benefit.

6 Impact of NERP Recommendations on the Demand Side

6.1 Triple whammy of higher energy prices, higher hedge costs and higher network charges

As discussed in the previous sections, end-use customers get a triple whammy as a result of the decision to increase VoLL from $5,000 /MWh to $20,000 /MWh. In the first instance there would be an increase in the average energy Price in the wholesale market. Due partly to the higher average rice and more due to the higher price volatility (due to the increase in the price cap), the endues customers would be faced with a increase in their hedge costs to manage the higher price volatility.
Finally, the end-use customers would also incur increased network charges due to VoLL being increased for the wrong reason.

6.2 Impact on Demand Side Response

The notion that by increasing VoLL there would be more demand response is more wishful thinking than any rational or verifiable outcome. With current level of VoLL the extent of hedge cover in the market is between 70% to 90%. When VoLL increases by four times, the only plausible outcome is hedge cover will increase rather than decrease. The more your load is hedged the less responsive you are to prices in the market. As Retailers operate on thin margins, they stake their very survival by taking exposure to pool price on the hope of profiting from active demand management. End use customers will be more weary than the Retailers of taking on such daunting potential for loss.

6.3 Impact on the Hedge Market

While the increased VoLL will drive more Retailers / end-users to take up hedge cover, generators without a diversified generation portfolio or having only limited load transfer options will be less willing to write hedges than they were when VoLL was lower. These opposing impacts on the two sides of the hedge market will translate to still higher hedge prices than due only to higher average energy price and their higher volatility.

6.4 Impact on Co-generation projects

Most co-generation projects require stand-by supply to ensure own production operations are not affected when their generation plant is down for maintenance or repair. As their smaller plant are more prone to forced outages than large power stations and they are unable to predict when such outages are going to occur, they face the unhedgable risk of pool prices being high when their plant goes down. Unless the nature of their production facilities enables complete shutdown without significant extra cost, this unhedgable pool price risk exposure could be a problem.

7 Impact of NERP Recommendations on the Management of Extreme Risk in the Market

In April 1998 NECA handed down a Determination regarding Force Majeure and the Administered Price Cap. In that Determination NECA had this to say on its pragmatic design of a test to establish a material force majeure event for applying the Administered Price Cap: "At the extremes of market reliability and prices involuntary load shedding in the order of 10 hours per year is a typical expectation / standard on a 1 in 10 year demand condition. Involuntary load shedding of 20 hours per year is an approximation to 1 standard deviation from market expectation of 10 hours per year.

The financial impact of 20 hours of involuntary load shedding is an accumulated pool price of $100,000 during the period of involuntary load shedding or a 48 hour average of approximately $ 2100/MWH. The materiality test has been set to initiate a *material force majeure* event if the accumulated pool price following at least one trading interval when physical involuntary load shedding has occurred. If the accumulated pool price (ie on a rolling 24 hour accumulation) continues at this level for a third 24 hour period (noting the requirement of clause 3.16.2 c) then an *Administered Price Period* is to commence.".

This Determination had the potential of VoLL prices continuing for 72 hours before the Administered Price Period would commence – a financial impact of $ 360,000 /MW of pool price exposure, when the intention seemed to have been to limit the financial exposure to $100,000 /MW (eg. financial impact of 20 hours of involuntary load shedding is an accumulated pool price of $100,000 during the period of involuntary load shedding or a 48 hour average of approximately $ 2100/MWH).

When taken in conjunction with Prudential Requirements and Retailer of Last Resort arrangements, this had the potential for systemic failure of the whole market.

Current proposal to have a 7 day Cumulative Price Threshold (s 3.14.1(c) $300,000 is incorrect, it should be 300,000 $*half hours or equivalent to $150,000/MW) as the trigger to reduce the market price cap (VoLL) to the Administered Price Cap is a much better outcome than the previous Determination. There are two problems with the present proposal:

- the equivalent accumulated pool exposure cost of $150,000/MW is still too high, being 50% higher than the original intention of $100,000/MW. It is excessive even on the basis of NERP argument for setting VoLL (6 hours at $20,000/MWh comes to only $120,000/MW)
- The current Administered Price Cap of $100/MWh Peak and $50/MWh off-peak, are proposed to substantially increase to $300/MWh on the basis of the highest operating cost of all the generators. Well, I still have to come across the generator who will not generate (at all) other than when the price reaches $300/MWh. Public benefit is not served by such investment.

Recommendation: The proposed changes constitute a transfer of resources from the demand side of the market to the supply side of the market with substantial increase in prices to end-users. The Benefit does not Outweigh the Detriment to the Public Benefit and as such the proposed change to the Administered Price Cap should not be approved.

Final Recommendation:

. The ambiguity of the term VoLL should be removed by appropriate code changes, keeping the term VoLL to mean Value of Lost Load. The Value of Lost Load should be properly determined by reference to the end-use customers expectations at least once in two years and should be one of the key yardsticks to evaluate the Price Cap in NEM

The Commission has previously accepted that the Price Cap is required because of the immaturity of the market. The last Vesting Contracts will be in South Australia and are due to expire by the end of 2002 only d as such full market maturity could be expected only after that date. The proposed big change in the Price ‿ap will have serious implications for the financial viability of some market participants as well as in containing the end-user impact of a calamity event. The Commission should require NERP give full economic justification by way of a rigorous cost / benefit exercise evaluating the impact of raising the Price Cap in NEM. The Administered Price Cap is meant to apply in instances of natural calamity and should be revenue neutral to all market players. The Administered Price Cap only applies after VoLL price has acted long enough to provide required revenue for the most expensive units in the market. The proper value for the Administered Price Cap (peak and off-peak) would have to be roughly equal to that seasonal average price for peak and off-peak periods – like during periods of Market Suspension (s3.14.5). Nobody should be allowed to PROFIT from natural disaster / calamity events. As an illustration, would the Commission take action if a rural petrol supplier put up the price to $ 100 / litre of petrol because the delivery bowser has broken down or there is a strike at the Victorian Shell Refinery? Why should not that petrol supplier make big bucks, the same as the electricity generators who are being allowed bigger bucks from unplanned (as far as expectations of profit) events / calamities when normal competitive market conditions do not apply?

It is EMRI view that the detriment to public benefits from the proposed change in the Price Cap and the Administered Prices, far outweigh the benefits to the public and the Commission should not approve such radical changes without closer scrutiny than as provided by the NERP Report.

Lasantha Perera
Director, Electricity Markets Research Institute

Appendix A

Office of Gas and Electricity Markets October 1999

Extracts from Decision Document 'Rises in Pool Prices in July'

1.2 Ofgem's July 1999 Consultation Paper

In July 1999, in response to a number of complaints from customers and suppliers, Ofgem published a consultation document on the very high level of prices experienced in the Pool during the first two weeks of July. Ofgem concluded that the high prices were the result of two factors. First, two of the major price setting generators, National Power and PowerGen, increased the prices at which they offered their coal-fired plant into the Pool, raising energy prices, known as System Marginal Prices (SMP). Second, the capacity element of Pool prices was very high, an apparent reflection of plant unavailability.

The combination of high SMPs and high capacity payments led to Pool Purchase Prices (PPP) spiking at over £120/MWh and an average PPP in the period 1 - 13 July of £32.52/MWh, some 80% higher than the same period during the previous year. Of the increase, around 62% was attributable to an increase in SMP and 38% to an increase in the capacity element.

Ofgem expressed concern that the recent Pool prices did not reflect underlying supply/demand fundamentals and were not representative of the prices that would be seen in an orderly market. Capacity margins had not been lower than usual over the period, but with the different mix of plant on the system, under the complex rules by which capacity payments are calculated, capacity payments were higher.

Ofgem noted National Power and PowerGen's views on the need to consider prices over a longer period. Ofgem also noted that average prices for the first six months of 1999 were over £24/MWh and that in any case, in a competitive market, it would not be possible to raise prices to compensate for perceived lower prices in earlier periods. In May 1999, OFFER had published a decision document in response to concerns about price spikes in the Pool during the winter of 1998/99 and the ability of generators to manipulate Pool prices. Following the Pool Executive Committee's (PEC) initiatives to limit the incidence of price spikes, Ofgem decided at that time not to take any action, but made clear that we would continue to monitor prices.

Given the subsequent rise in Pool prices, we set out our initial view in the July consultation document that changes to the Pool's trading rules would be insufficient to address renewed concerns about the large increases in the level and volatility of Pool prices.

1 'Ofgem Consultation on Rises in Pool Prices in July', Ofgem, July 1999.

1.3 Pool Prices Since Ofgem's July Consultation Paper

Since the launch of the July consultation, Pool prices have fallen but have remained relatively high. Over the period 16 July to 17 September, PPP peaked at over £135/MWh and averaged £25.70/MWh, some 49% higher than the same period during the previous year. Of the increase, around 41% was attributable to an increase in SMP and 59% to an increase in the capacity element.

1.4 Respondents' Views

In total Ofgem received 29 responses to the July Pool price consultation paper. All responses, apart from 4 whose authors sought confidentiality, have been placed in the Ofgem library. These responses are available for inspection during normal working hours.

Generally, respondents expressed concern that the wholesale electricity market continues to be manipulated by generators to the detriment of customers. Concern was also expressed that Pool prices still fail to reflect the falling costs of generation. Several respondents questioned the validity of the relationship between plant margin and capacity payments. Some respondents had additional concerns about the impact the high prices had upon forward contract markets.

Three generators expressed concern over the relatively short period in July that was the focus of Ofgem's initial investigation and pointed to the overall downward trend in Pool prices when viewed over a longer `ne period. One generator also pointed to the lower prices experienced in the Pool in April, May and June _nd noted the lack of customer complaints during these months. This generator also suggested that recent Pool prices were an expression of market volatility, which is to be expected in a commodity market.

Respondents put forward a variety of views as to the way forward, including:

- reform of the Pool Rules;
- modifying generator licences; and
- other proposals, including fining National Power and PowerGen.

3.4 Conclusions

The history of the Pool to date and previous OFFER investigations have demonstrated the ability of certain generators to manipulate prices in the Pool and provided evidence of actual manipulation of prices by generators to their own benefit at the expense of customers. The present detailed investigation in to Pool prices in Summer 1999, the third investigation in three years, provides more evidence of the ability and willingness of certain generators to exercise their market power. Generators are able to raise prices as a result of the limited competition amongst price setting plant, the lack of effective demand side participation and the complexity of the trading rules that determine Pool prices.

The present investigation has also highlighted the problems associated with the current rules used to calculate capacity payments. Under the current rules, capacity payments do not send appropriate price signals in the short or long term. The problems associated with the calculation of capacity payments are likely to increase over the coming months because of the amount of capacity on the system commissioned in recent years.

6.3 The New Licence Condition

Consistent with general competition law, the new licence condition requires each licensee to which it applies not to abuse a position of substantial market power in electricity generation. Its inclusion in the licence of any particular company does not imply that the company does, in fact, enjoy a position of substantial market power. As indicated in the condition, this will be a matter for determination in the light of the circumstances of the time. Ofgem recognises that these circumstances can be expected to change, so that a licensee that possesses substantial market power at one time may cease to do so at some later time, and that licensees that initially have little market power may acquire much greater strength later.

The initial list of licensees to whom the condition will apply is, therefore, simply an initial attempt to identify those companies most likely to possess the ability to influence Pool prices to an extent, and for a time long enough, to have an appreciable effect on consumer interests. Ofgem would prefer to introduce the condition into all generation licenses, but has identified the need to concentrate in the first instance on those licensees who are most likely to be in a position to exercise substantial market power. If, however, a licensee not on the initial list is, at a later date, judged to have increased its market strength to an extent where there was a significant likelihood that it could exert a substantial influence on wholesale prices, the Director General will take steps to incorporate the condition in to its licence.

Ofgem would also like to emphasise that:

- There is nothing in the condition to undermine the well established principle that it is the abuse, not the existence, of substantial market power that gives rise to problems.

- Where a licensee does not have a position of substantial market power, questions of abuse do not arise, irrespective of whether or not the condition is in its licence.

Thus, firms that either do not possess substantial market power or that, although they enjoy such power, do not seek to abuse it, will be unaffected by the condition. The full legal text of the proposed licence condition is set out in Appendix 1.

6.4 Coverage of the New Licence Condition

The list of generators whose licences Ofgem will seek to modify have been determined on the basis of their share of total output and the frequency with which they have set SMP in the Pool. The list of generators is shown in table 6.1.

Table 6.1 - Coverage of the New Licence Condition

Company	SMP setting (1 Oct 98– 30 Sep 99)	Share of Output (Sep 98 – Sep 99)
National Power	27.3%	17.6%
PowerGen	27.9%	16.7%
Eastern	23.0%	7.7%
Edison	5.3%	1.4%
AES	5.0%	2.1%
Nuclear Electric	0%	16.5%
Magnox	0%	7.8%

Note: The table excludes the full impact of the divestment of Fiddler's Ferry, Ferrybridge and the planned divestment of Drax. AES' and Edison's share of output and ability to set SMP will rise and National Power's and PowerGen's share of output and ability to set SMP will fall.

6.5 Interpretation of the New Licence Condition

Draft guidelines on the interpretation of the new licence condition are set out in Appendix 2, but the following general points apply:

- Where concerns about possible breach of licence arise, the first step will be to determine whether the licensee does, in fact, hold a position of substantial market power. Under current trading arrangements, the test will be whether the firm can, unilaterally, via its own bidding behaviour, influence Pool prices to an extent that causes appreciable harm to those purchasing electricity in the relevant periods.
- The list provides examples of possible abuses, but is not exhaustive of possible abuses.
- Example (a) refers to straightforward restrictions of supply, and encompasses Pool behaviour such as bidding in less output than is feasible, bidding in part or all of output at high prices that bear no relation to costs, artificially restricting the capacity made available to the market, and the closure or mothballing of capacity that it would be economic to operate.

- Example (b) concerns discriminatory behaviour. In relation to the Pool, since a single price is set in each period, there can be no question of different prices being set for similar supplies (although this can be an issue in contracts markets, including, post-NETA, in any power exchanges that might be operating). There could, however, be a breach of licence if a company substantially varied the mark-up of bid prices on costs as between periods when market conditions were otherwise similar, which is one of the issues that has been raised by this investigation. Whether or not such conduct would amount to a breach would depend, among other things, on whether or not the licensee had substantial market power and on the extent of the effects of such conduct on Pool prices.

- The final example, (c), recognises the extra obligations that licensees have as a result of the requirement for secure operation of the electricity system. All licensees have responsibilities in this area, but companies with substantial market power are likely to be able to exert the greatest influence on system operation, the costs of system operation, and the resulting level of charges that are levied to recover those costs.

Appendix B

Diagnosing Market Power in California's Deregulated Wholesale Electricity Market

By Severin Borenstein, James Bushnell and Frank Wolak (July 1999)

Abstract: Effective competition in wholesale electricity markets is the cornerstone of the deregulation of the electricity generation industry. We examine the degree of competition in the California wholesale electricity market during June-November 1998 by comparing the market prices with estimates of the prices that would have resulted if all firms were price takers. We found that there were significant departures from competitive pricing and that it was most pronounced during the highest demand periods. Overall, this raised the cost of power purchases by about 22% above the competitive level. We also explain why the prices observed cannot be attributed to competitive peak-load pricing.

Appendix C

Report on Redesign of California Real- Time Energy and Ancillary Services Markets

By Dr. Frank Wolak
Chairman of the ISO Market Surveillance Committee
Subm itted to FE RC on October 19, 199

- Market Performance during the summer of 1999 versus the summer of 1998:
  - the performance of the ISO's ancillary services markets during the summer of 1999 appears to be significantly improved relative to the same month during the summer of 1998. However, a substantial proportion of this improvement in market performance can be attributed to lower average hourly total system loads.
  - that significant market power remains in California's wholesale energy market during periods of high total system load, which primarily occur during the summer months.
- the total amount of market power exercised during July 1999 appears to be significantly less than that exercised during that same month in 1998.
- that the opportunities for the exercise of market power in the ISO's ancillary services markets are greater when these markets are cleared on a zonal versus statewide basis.

Main Recommendations

- The report offers recommendations for correcting some of the remaining market design flaws identified in previous MSC reports. The remaining market design flaws include:
  - rules for dispatching Reliability Must- Run (RMR) contract generation units
  - the lack of a price- responsive hourly wholesale electricity demand
  - the inability of utility distribution company loads to forward contract for their energy and ancillary services demands outside of the PX markets.
- The recommendations include:
  - pre- dispatch and mandatory day- ahead scheduling of RMR capacity
  - Allowing the ISO to have the authority to impose a purchase price cap on its energy and ancillary services markets, at least until all remaining major market design flaws are eliminated.
  - the ISO maintain the current $750/ MW price cap at least through the end of the summer of 2000. At this time, enough information on the performance of the ISO's markets under the new ancillary services market design and new RMR contracts will be available to evaluate whether removal or raising of this price cap is warranted.

Appendix D

Electricity Markets Research Institute (EMRI) undertakes research with primary focus on:

- Public benefit aspects of competitive electricity markets:
- Technical and market efficiency,
- Equity issues,
- Transition issues going from integrated utility in a monopoly market to competitive marketing.

Other research & consultancy work cover:

- retail pricing and value studies,
- demand forecasting,
- demand side response,
- network and ancillary services pricing,
- pricing of externalities eg Greenhouse Gas Emissions.

Contact Details:

Lasantha Perera, Director
Electricity Markets Research Institute
P. O. Box 6158,
Vermont South VIC 3133, AUSTRALIA

Telephone : +61 3 9803 7170
E-mail : lasantha@bigpond.com

Biography of Lasantha Perera, Director - National Electricity Markets Research Institute

Until July 1999, was Manager Pooling with Eastern Energy Ltd. Played a significant part in the deliberations of various bodies connected with the setting up of the National Electricity Market, including membership in the Dispatch and Pricing Reference Group. Was a founding member of the National Retailers Forum and have made many submissions to NEMMCO, NECA and the ACCC on different facets of the National Electricity Market.

Was inducted into Eastern Energy at its inception in 1994 and as Manager Pricing and Forecasting set up their Pricing and Forecasting section, participated actively in the trade sale process and managed the contestable customer pricing process.

As Pricing Analysis Manager with SECV spent seven years working on pricing development, cost of supply studies and the development of industry cost models, and defining price paths to reduce cross-subsidies. Was an active participant in the Victorian Electricity Supply Industry Restructuring process involving industry codes, Tariff Order and network pricing.

Has a MSc in Technological Economics from the University of Stirling in Scotland, is a Chartered Engineer with both the Electrical and Mechanical Institutes in the UK.