Electricity Markets Research Institute

Director ABN 6839 802912
Lasantha Perera, MIEE, MIMechE, FIE (Sri Lanka), CEng
BSc, DipEE, MSc Technological Economics (Stirling)

Australian Energy Market Commission
PO Box A2449
SYDNEY SOUTH NSW 1235

Via Email: submissions@aemc.gov.au

5 June 2009

Submission on the Draft Report by AEMC on Review of Demand Side Participation in the NEM

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), over 15 years experience in electricity cost modeling and pricing development, both under a regulated environment and in the new competitive market and a keen interest in the techno-economics of energy use in Australia.

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

- Public benefit aspects of competitive energy 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 Attachment A.

1.0 Introduction

The Australian Energy Market Commission (AEMC) is to be congratulated on the detailed analysis of demand side response options **currently available** in the local market and possible improvements based on experience from other countries like USA, UK, New Zealand, etc. (existing paradigm). Technology development is not frozen in time and countries like USA, UK, and New Zealand do not have a monopoly on technology development. New industry developments also create new opportunities for process / procedure / rules adaptation. While some of the new technologies may not yet be proven in operation, they have all been proven in similar applications. There is merit in considering them if they **inform the development options available to the energy industry in the next 5 to 10 years.**

This submission will therefore be structured as follows:

A. provide a simplified account of the brand new technologies that will fashion demand side response in the near future. More detailed account is given in the accompanying Confidential part of the submission;
B. briefly discuss new imperatives that will substantially alter future energy industry structure;
C. scenarios presented will then be used as reference to provide comment to the points raised in the AEMC draft report, drawing on the very substantial experience of the author in the field of electricity pricing;
D. explore options for interface with the National Electricity Market Operations;
E. Recommendations.

A.1 New technology developments not considered before:

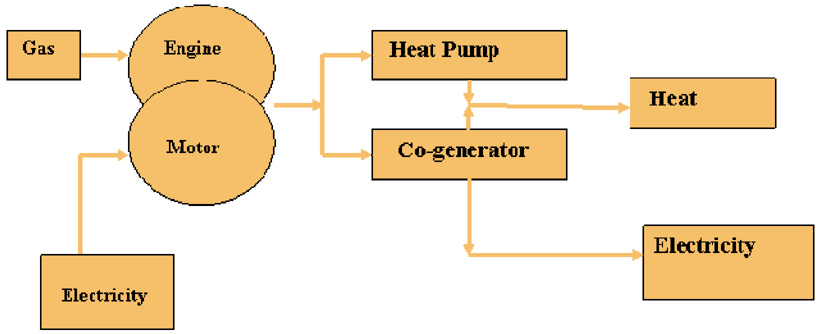
- Opportunity Power ™ a new technology package[1] that combines
  - a new type of dynamic real-time retail energy contract that contain provisions to limit pool price exposure risk but able to access financial gains from price excursions in the pool market;
  - provision to add further incentive payments from retailer, network operator, electricity market operator, or demand response aggregator;
  - provision for incentive payments to be location / region specific;
  - a fully automated demand response system covering key loads installed at the premises, in communication with smart meter installed at the premises, able to access pool price and price forecast information, able to disconnect or reconnect loads on occurrence of specified conditions;
  - conditions for disconnecting or reconnecting loads dependent on type of load being served and customer attributed value of using that load;
  - the diligent operation of which enables substantial financial gain with minimal exposure to pool price risk;

- Energy Arbiter™ a new[2] type of automated co-generator plant that enable key customer loads (eg HVAC, water pumping, compressor operations, etc) to arbitrage between energy sources, between electricity import / export and between energy efficient technologies (co-generation and heat-pumps in the case of building systems). The key component being a gas fuelled engine, whose local production / assembly will benefit from availability of components / suppliers resulting from recently announced local production of electric hybrid cars (Toyota has recently announced[3] the global first commercial production of natural gas – electric hybrid cars).

[1] Covered by Australian Patent No 748800, patent granted in NZ, pending in USA, Canada & Europe
[2] Covered by Australian Patent No 2004907153, patent pending USA, Canada, Europe, Japan, China, India & NZ
[3] http://www.themotorreport.com.au/12702/toyota-unveils-cng-camry-hybrid-concept/

EMRI, 4 Baranbali Drive, Vermont South, Victoria 3133 Australia

Telephone: +61 3 9803 7170 Email: lasantha@bigpond.com
Mobile: 043 9803 717



Hydronic heating systems - widely used in Europe, are employed facilitating the combining of water and space heating applications. Including an intermediate thermal storage facility enables optimum technical, operational and financial outcomes. The system is further optimised by use of a supplementary solar or ground thermal facility to improve heat pump operations, specially under extreme hot or cold ambient conditions.

- Within the last decade there has been a progression of combustion engine developments such as substantial improvement in diesel engine performance eg. Cummins Inc demonstrated[4] in May 2005 an ISX heavy-duty truck engine with an increased Brake Thermal Efficiency (BTE) of 45 percent while simultaneously reducing emissions as well. Launch of electric - petrol (and diesel) hybrids is already being outperformed by the Honda Civic GX running on natural gas and very recently Toyota has announced the [5] the global first commercial production of electric - natural gas hybrid cars. These developments bode well for the performance improvement of small gas engines suitable for distributed co-generation.

B.0 New imperatives that will substantially alter energy industry structure in the near future include the following:

B.1 Coal will lose its place as the lowest cost fuel for electricity generation

At present the difference in long run marginal cost between centralised coal power plant and combined cycle gas turbines (CCGT) is relatively small if a reasonably high utilisation factor is used for the gas turbine. Since a CCGT emits only about one third the GHG emissions from a coal power station, the coal power stations will lose their present cost advantage with the introduction of carbon trading.

Further, economy of scale from large power stations at remote locations cannot compare with improved conversion efficiencies of gas fired co-generation at the customer premises, more so if the premises already have a gas connection for other purposes.

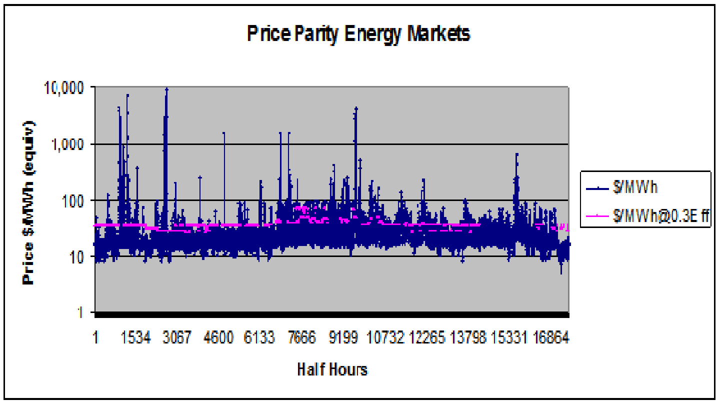
[4] See "Cummins demonstrates technology road map for high-efficiency engine with U.S. Department of Energy" at http://www.cummins.com/cmi/content.jsp?dataId=2282&anchorId=453&menuIndex=none&feed=1&siteId=1&overviewId=15&menuId=4&langId=1033&

[5] http://www.themotorreport.com.au/12702/toyota-unveils-cng-camry-hybrid-concept/

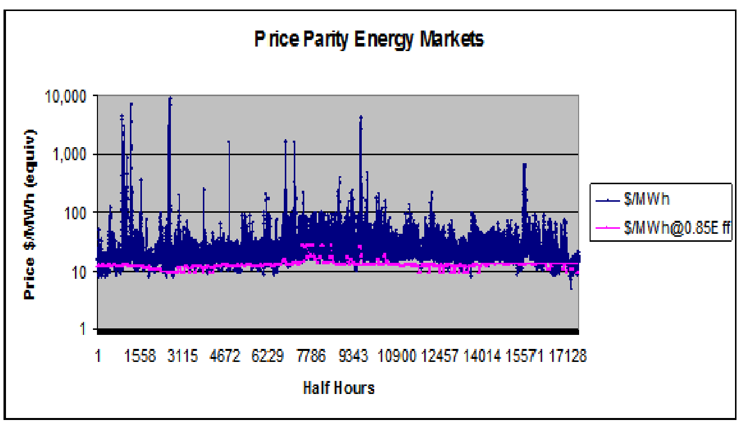
EMRI, 4 Baranbali Drive, Vermont South, Victoria 3133 Australia

Telephone: +61 3 9803 7170 Email: lasantha@bigpond.com
Mobile: 043 9803 717

The graph below superimposes the 2006 Victorian Region National Electricity Market half hour price for electricity on to the Victorian gas market price for 2006 converted to electricity at a conversion efficiency of 30% applicable to the gas engine driven generator. What we can see is that the fuel cost on the gas market for such a generator is less than the electricity cost in the NEM wholesale market for quite a number of half hours, while making a handsome return during the many half hours when the pool price was above $100/MWhr.



What if the generator conversion efficiency is improved by making it a co-generator, where exhaust heat from the engine is recovered for supplying the premises hot water requirement? A reasonable conversion efficiency then would be 85% and the same graph is reproduced below but with the increased efficiency.



Ureka, for most of the time gas generated electricity is now cheaper than off-peak period (bottom dips) pool prices mostly determined by coal power stations. If we can further increase efficiency, it is a bonus. A point many people miss is that 85% efficiency is for the whole co-generation system, but the opportunity impact is still 85% when you net-out useful heat which remains the same with or without the project. To illustrate the aspect of opportunity impact, say 200 units of gas was used. It will produce 200 x 0.40 units of electricity and 200 x 0.45 units of heat. So we end up with little more heat output (=90 units) than the gas only application of 100 units at 85% efficiency for the stand alone gas appliance which gives 85 units of heat, giving

EMRI, 4 Baranbali Drive, Vermont South, Victoria 3133 Australia

Telephone: +61 3 9803 7170 Email: lasantha@bigpond.com
Mobile: 043 9803 717

rise to the opportunity outcome of 80 units of electricity from the marginal use of 100 units of gas. Assuming the value in 'little more' heat units offsets the value in 'little less' electricity units.

B.2 Gas will become the fuel of choice and availability of a gas connection will become the future Universal Supply Obligation for energy customers in temperate climates

The almost universal incidence of gas use for space and water heating in areas where reticulated gas supply is available is ample testimony to the cost efficiency of using gas for such purposes. Since space and water heating constitute around 70% of energy used in residential and small business premises in Australia, these customers have a substantial saving in energy costs.

Few people appreciate the fact that energy transport in the form of gas is far cheaper than in the form of electricity. An October 2005 report[6] by Vencorp entitled "25 year vision for Victoria's Energy Transmission Networks" substantiated this very clearly. In 2006-07 Victoria used more gas (252 PJ) than electricity (158 PJ).

	GASNET'S GAS TRANSMISSION NETWORK	**SP AUSNET'S ELECTRICITY TRANSMISSION NETWORK**
Transmission asset value per PJ of energy delivered	$2.2 million/PJ	$8.9 million/PJ
Transmission asset augmentation costs to 2030	$445 million	$1,505 million

Victoria has high penetration of gas use, around 1.7 million supply connections compared to 2.4 million electricity connections (2007), which shows the gas transmission system in Victoria is very extensive. Actual customer dispersion is more a cost driver for the distribution system than for the transmission system. So the 3 to 1 ratio favouring **gas as a form of energy transport** is inherent in the energy form. As people familiar with electricity transmission systems would appreciate, gas transmission being mostly via underground pipelines, are more reliable than electricity transmission, as they are immune to bushfires, storms and lightning strikes, reactive power problems, no need for fault level controls, etc.

Comparing the existing gas transmission system in Australia with the map[7] of existing electricity power stations / transmission system, it is very evident that gas transmission is extremely vital for efficient development of Australia, both to improve living conditions for remote communities and to better utilize our natural resources, making possible increased value adding rather than be content with direct export of our mineral wealth.

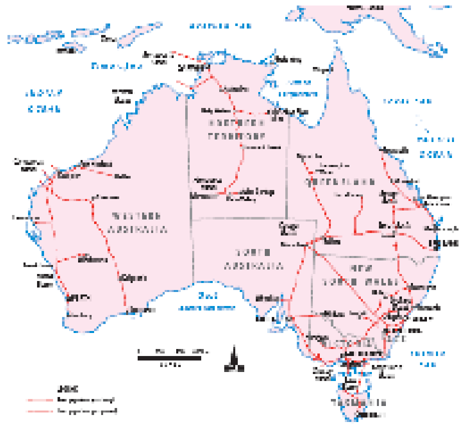
---

[6] **See**
http://www.vencorp.com.au/index.php?action=filemanager&pageID=7742&sectionID=7720&searchstring=vision+2030&search=search&search.x=43&search.y=9

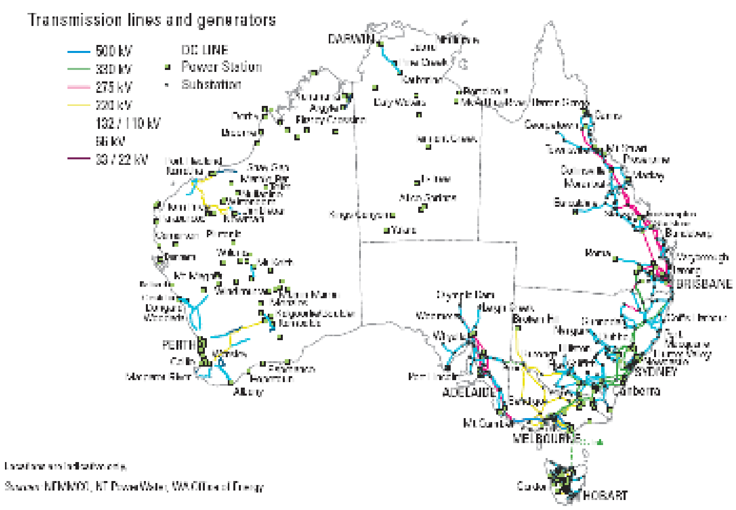
[7] Source: ABARE Energy in Australia 2009

EMRI, 4 Baranbali Drive, Vermont South, Victoria 3133 Australia

Telephone: +61 3 9803 7170 Email: lasantha@bigpond.com
Mobile: 043 9803 717



Happily for remote areas in Queensland, the new found coal seam gas (methane) is facilitating setting up of remote area power stations, but it would be a great pity if the massive involvement of the global oil and gas companies and their inordinate rush to line up export facilities, were to deny gas resources needed to develop Australia, provide jobs for Australians and help reduce national GHG emissions without causing a heavy burden to Australian households. All governments have a duty to facilitate such essential services (gas) in the same vein as to provide roads and railways.



As indicated by the current map of the existing gas transmission system in Australia, achieving a fully interconnected national gas grid is timely and becoming urgent. The expansion of the scope of the national electricity market and related planning / regulatory bodies to include gas as from 1 June 2009 is a good start.

B.3 Gas supply and price will be driven by new forms of gas

For over a decade very substantial natural gas reserves in the North West corner of Australia has idled because of the distance from major markets and very substantial costs associated with developing LNG market / transport systems. Equally substantial

EMRI, 4 Baranbali Drive, Vermont South, Victoria 3133 Australia

Telephone: +61 3 9803 7170 Email: lasantha@bigpond.com
Mobile: 043 9803 717

coal seam methane resources have now been discovered[8] in Queensland and New South Wales, with good prospects of similar deposits being found in Victoria, South Australia, Northern Territory and Tasmania. In Australia and elsewhere, demonstration projects have established viability of producing synthesis gas by underground gasification of coal, able to access vast coal deposits too difficult to mine through traditional mining methods. In the next decade Australia would have much more relatively cheap gas than there is readily available coal, a fact recognised by major international O&G companies like Shell, ConocoPhillips, British Gas, Petronas, Mitsui, Gastar, Sojitz, etc.

B.4 Compressed natural gas / methane will replace petroleum products like petrol, diesel and LPG currently being used for transport vehicles

Latest available regional count was taken in 2008[9] (given below), showing a phenomenal growth in worldwide natural gas vehicle numbers over the last three years.

Region	2008 NGV Count	Refueling Stations	2005	2006	2007
ASIA	4,380,412	5,925	1,167,761	1,823,993	2,795,476
EUROPE	1,109,796	3,052	600,926	760,934	877,722
NTH AMERICA	125,177	1,204	113,542	105,177	115,177
STH AMERICA	3,784,664	4,220	2,649,325	3,003,575	3,521,136
AFRICA	101,326	126	64,155	76,003	84,994
WORLDWIDE	**9,501,375**	**14,527**	**4,595,709**	**5,769,682**	**7,394,505**
Percent growth on previous year	28.5%		17.1%	25.5%	28.2%

Honda had their commercial release of the Civic GX - their natural gas car, in the USA six years ago and since then it has been named the 'greenest vehicle' sold in the US by the American Council for an Energy Efficient Economy (ACEEE) – beating all gasoline vehicles, including all the gasoline hybrids.

Australia price comparison for energy product export / import ($/GJ)

	Exports		Imports	
	2006-07	2007-08	2006-07	2007-08
Crude oil	14.7	18.5	14.9	18.5
Automotive gasoline	18.8	21.9	19.9	**23.8**
Diesel fuel	18.1	21.8	17.7	**22.8**
Liquefied petroleum gas (LPG)	15.3	19.0	14.5	**18.8**
Liquefied natural gas (LNG)	6.3	**7.3**		

Data source: http://www.abareconomics.com/interactive/08ams_dec/excel/ams_tables.xls

Australia is blessed with abundant sources of energy. Our immense reserves of coal are able to give us vast quantities of clean energy – coal seam gas or methane. The scramble by major global energy companies to lock in control of these vast reserves

[8] Santos estimate 250+ Tcf in Eastern Australia compared to 200 Tcf in the NW shelf, see: http://www.santos.com.au/Archive/library/Santos%20Roadshow%20Mar%202009%20A5_ASX_cover.pdf

[9] http://www.iangv.org/tools-resources/statistics.html

EMRI, 4 Baranbali Drive, Vermont South, Victoria 3133 Australia

Telephone: +61 3 9803 7170 Email: lasantha@bigpond.com
Mobile: 043 9803 717

speaks volumes. The table above is extracted from Australian Mineral Statistics report produced by ABARE, but converted to a common denominator, the price of energy in dollars per Giga Joule ($/GJ).

Australia imports automotive gasoline and diesel at around three times the price of export LNG (easily substitutable for petrol and diesel). LPG price is substantially more than twice LNG price.

Full cycle GHG emissions for common transport fuels are given in the Table[10] below and it shows a benefit of about 15.5% for heavy duty vehicles (11.5% for light duty vehicles) when converting from petrol or diesel to natural gas:

	Energy content (GJ/kL)	**Full fuel cycle emission factor kg CO2-e/GJ**
Automotive gasoline (petrol)	34.2	77.2
Automotive diesel oil (diesel)	38.6	77.6
LPG	26.2	69.3
	GJ/m^{3}G	**kg CO2-e/GJ**
Natural gas ^{b} (LDV ^{c})	0.0395	68.6
Natural gas ^{b} (HDV ^{c})	0.0395	65.2

b. The emission factors for natural gas engines are indicative only. From AGO experience with the Alternative Fuels Conversion Programme, the AGO has discovered that many natural gas engines, whether dual fuel or dedicated, emit significant amounts of unburnt fuel to the atmosphere. This level of methane is dependent on a range of factors and varies from system to system. An accurate emissions factor therefore requires measurement of at least CO2 and CH4 for each engine type.
c. LDV stands for Light Duty Vehicles, e.g. forklifts, and HDV stands for Heavy Duty Vehicles, e.g. buses.

A study by California-based TIAX LLC[11] has confirmed a 21% reduction in greenhouse gas (GHG) emissions in LNG trucks featuring a Westport ISX G engine and LNG fuel system based on a 10 year, 400,000 mile well-to-wheel (WTW) scenario. Under this scenario, a typical Westport LNG-equipped natural gas truck operating at the San Pedro Bay ports in California will realize reductions of 21 tonnes of GHG emissions per year compared to an equivalent diesel truck and includes upstream emission factors as well.

A June 2008 CSIRO report[12] also has pointed to a greater role for gas in the Australian transport sector:

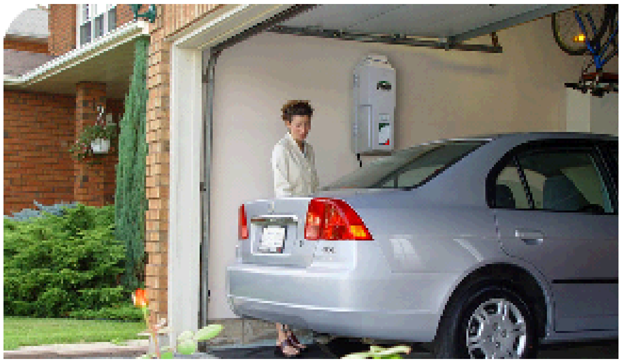
"In this context, domestic natural gas use in transport and other sectors may still demand a significant and potentially growing share of total Australian gas production, particularly in road freight. Modelling indicated as much as an ***additional 200PJ per annum*** *of natural gas could be required for the Australian transport sector by 2020 relative to the approximate 900PJ currently used in manufacturing processes and electricity generation. Current use of natural gas in Australian transport is* ***less than 2PJ****".*

[10] http://www.environment.gov.au/atmosphere/ozone/publications/pubs/cold-hard-facts.xls
[11] http://www.westport.com/pdf/GHG_and_Criteria_Pollutant_Emissions_Estimator.pdf
[12] See **Fuel for thought - The future of transport fuels: challenges and opportunities** @ http://www.csiro.au/files/files/plm4.pdf

EMRI, 4 Baranbali Drive, Vermont South, Victoria 3133 Australia

Telephone: +61 3 9803 7170 Email: lasantha@bigpond.com
Mobile: 043 9803 717

For the USA market, FuelMaker has introduced Phill[13] - the world's first appliance that lets you refuel your Natural Gas Vehicle indoors or outdoors from your household natural gas line as shown in the picture below. In Australia close to 50% of premises having an electricity connection also have a gas connection. Most major towns have gas lines. Setting up a gas filling facilities is much easier than setting up facilities for LPG.



Courtsey FuelMaker

The many energy regulators, experts and consultants advising the federal and state governments is doing a disservice to Australia and Australians by not advising relevant decision makers that natural gas for transport vehicles needs to be fast tracked with immediate effect.

There is close synergy effects between energy efficient technologies mentioned above and use of gas as fuel for transport vehicles. Both benefit from improved gas transmission and distribution network development, leading to almost universal gas connections to residential and business premises. In addition to that, gas engine development work and component availability will help both purposes, as well as the increased emphasis on skills development, standards formulation and service capability. Size of gas cogeneration equipment depends on the host facility and there is need for engine sizes that go from small to very large engines that would be equivalent to the size of rail engines.

B.5 Rapid growth in co-generation and heat pumps will lead to reduced dependence on centralised coal / gas power stations, reducing stress on power systems and reducing need for power system augmentation;

B.5.1 Heat Pumps

- Heat pumps with high coefficient of performance (COP 3 to 6) can pluck heat from ambient air equivalent to 3 to 6 times the energy input to the heat pump;
- The compressor – the core of a heat pump, has significantly improved in performance with the introduction of scroll type impellers and use of carbon dioxide as the refrigerant;

[13] See www.myphill.com

- Heat pumps improve utilisation of low level heat and cold from ambient air, significantly increasing effectiveness of solar / ground thermal applications. European Parliament legislative resolution passed on 17 December 2008 recognises for the first time aerothermal and hydrothermal energy **as sources of renewable energy under EU law**;
- There is synergy effect of combining heat pumps with solar / ground thermal applications, avoiding significant deterioration of heat pump efficiency at extreme temperatures (hot or cold) that would occur otherwise. This then reduces the big drain on mains energy supplies. For example, on very hot summer afternoons the heat pump air-conditioners have to work harder since their efficiency drops with increased ambient temperature. Unfortunately, this is the very time when the energy delivery capacity of the power system also gets de-rated because higher ambient temperatures reduce the cooling available to operating power lines and electrical plant. This triggers plant tripping when they reach thermal limits for safe operation;

B.5.2 Co-generation

- Co-generation increases efficiency of energy conversion (85% compared to 30% when displacing the lowest efficient generator) to be substantially higher than in any big conventional or new technology power station;
- Large scale co-generation by end users (distributed generation) reduces pressure on already strained transmission and distribution systems, saving on power systems augmentation costs and eliminating power line and transformation losses (8% – 15%);
- By incorporating load buffering eg thermal storage capacity, opportunity is created for electricity output from co-generation to derive best financial returns taking account of peak periods in network loading / electricity market operations;

B.6 Global Warming and Carbon Trading will have huge impact on the electricity industry and challenge the growth capacity of the gas industry

As shown in table[14] below, stationary energy and transport account for around 65% of GHG emissions in Australia, with around 50% being due to stationary energy.

	Emissions Mt CO2-e		**Percent of total emissions**	**Percent change in emissions**
	1990	**2006**	**2006**	**1990 - 06**
Energy	286.4	400.9	69.6%	40.00%
Stationary Energy	**195.1**	**287.4**	**49.9%**	**47.30%**
Transport	**62.1**	**79.1**	**13.7%**	**27.40%**
Fugitive Emissions	29.2	34.5	6.0%	18.10%
Industrial Processes	24.1	28.4	4.9%	17.70%
Agriculture	86.8	90.1	15.6%	3.80%
Waste	18.8	16.6	2.9%	-11.40%
Land Use Change(a)	131.5	62.9	10.9%	-52.20%
Forestry (b)	0	-23	NA	NA
Australia's Net Emissions	**547.7**	**576**	100.0%	**5.20%**

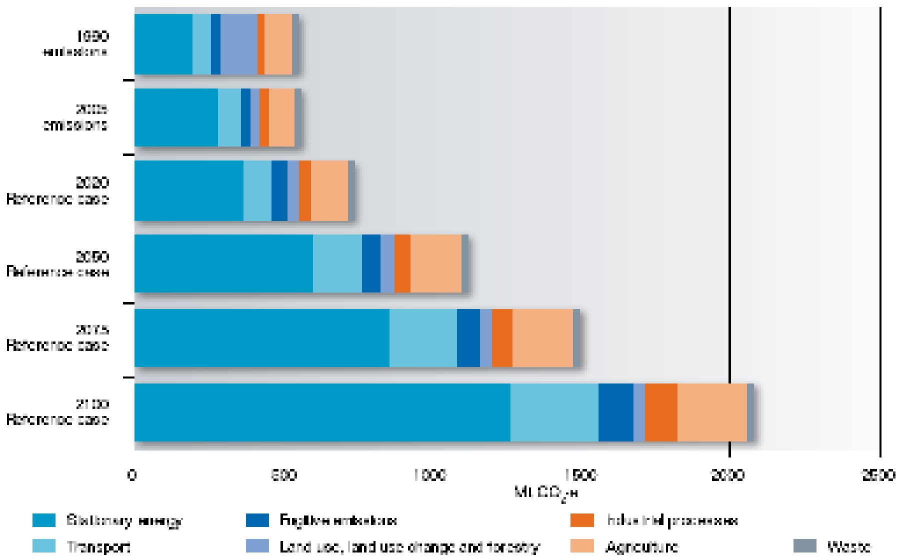
[14] Source: Australias Greenhouse Gas Emissions fact sheet 5 - Dec08
See: http://www.climatechange.gov.au/whitepaper/factsheets/pubs/005-australias-greenhouse-gas-emissions.doc

EMRI, 4 Baranbali Drive, Vermont South, Victoria 3133 Australia

Telephone: +61 3 9803 7170 Email: lasantha@bigpond.com
Mobile: 043 9803 717

A more worrying fact is the extremely high growth in emission between 1990 and 2006. For stationary energy the emissions increase was 47.3% and for transport it was 27.4%. It is worth noting that close to 40% of stationary energy use[15] is consumed by the residential and commercial sectors, and is predominantly energy used for building services.

Greenhouse gas emissions by sector: 1990, 2005 and reference case scenarios



The graph above, taken from the Garnaut Climate Change Review Draft Report of July 2008, show that Reference Case projections up to 2100 also indicate very significant growth in emissions from stationary energy and the transport sectors. The proposed new technologies described previously are well suited to arrest such growth.

A key outcome of the successful implementation of the proposed paradigm shift is the very substantial **reduction in GHG emissions** with no ifs and buts, the extent and timing of benefit flows depending on industry and governments efforts to facilitate speedy technology adoption / diffusion. Renewable energy sources like wind and solar photovoltaic are intermittent and so can only replace marginal generation which is mostly natural gas. Energy Arbiter™ replaces base load generation[16] which is mostly brown or black coal. Electricity from a gas turbine power station give GHG emission reductions of 66% (brown coal case) and 50% (black coal case) respectively. On top of this, generation at the customer premises will give a 15% reduction due to savings on station use of energy and transmission / distribution line losses. Further, as co-generation increases conversion efficiency from 55% for a combined cycle gas turbine to around 85% (after heat recovery & allowing for internal combustion engine losses), there is a further 30% efficiency benefit. Resulting net GHG emission reduction are

[15] **Source:** Australia's National Greenhouse Gas Inventory - 1990, 1995 and 1999, End Use Allocation of Emissions. Report to the Australian Greenhouse Office by George Wilkenfeld & Associates Pty Ltd and Energy Strategies, 2003

[16] As Energy Arbiter™ includes heat storage capacity like in a refrigerator, normal operation is in the form of cyclic bursts. The aggregate of a large number of such activity (diversity factor) gives a fairly steady generation output (equivalent to base load plant), spread though out the 24/365 cycle, except for occasional peaks coinciding with pool price excursions – very desirable as it happens mostly during periods of energy / supply capacity shortage.

EMRI, 4 Baranbali Drive, Vermont South, Victoria 3133 Australia

Telephone: +61 3 9803 7170 Email: lasantha@bigpond.com
Mobile: 043 9803 717

around 80% (of brown coal case[17]) and 70% (of black coal case[18]). By generating own electricity requirements and exporting excess amounts of electricity, the net reduction in GHG emissions will vary between **62%** (generate only sufficient electricity to cover own use) to **117%** (co-generating electricity to fully cover own heat requirement will give a substantial net export of electricity reducing more GHG emissions). Such substantial and definite reduction in GHG emissions is a far better outcome than pursuing an elusive promise of 'Clean Coal FutureGen plant' at significantly higher cost.

Assessing certainty of outcome extends to evaluating prospects of technology uptake and diffusion. Given the economic life of premises space and water heating units are between 10 and 15 years, and taking into consideration the substantial financial benefit from the new technology package, with good marketing the technology package will be adopted by almost all customers having a gas connection - well within 20 years, ie before 2030.

B.7.1 Electricity pool market design still evolving

The Victorian Power Exchange (expanded to become the National Electricity Market) closely replicated the original compulsory gross pool market model developed in the United Kingdom, which itself was based on the then existing economic despatch model. The reasoning was that fixed costs were already 'sunk' and as such economic efficiency lay in reducing short run marginal cost. It took for granted the theory of 'economy of scale' according to which electricity from centralised large power stations provided the lowest per unit cost. As discussed under the sections on Heat Pumps and Co-generation, physical laws are immutable and must be considered first before applying economic theory.

B.7.2 Challenge ahead for electricity generation sector

Energy Supply Association of Australia estimates[19] capital expenditure in the generation sector over the next 5 years is between $17-19 billion. The current value of energy supply industry assets is estimated at over $120 billion. The industry is worried that there will be a value loss between $ 2 billion and $ 10 billion in the first decade following the introduction of the Carbon Pollution Reduction Scheme (CPRS).

B.7.3 Challenge ahead for energy networks

According to Parsons Brinckerhoff Report[20] to ENA, "highest risks (from climate change) arises from bushfire, tropical cyclones and a change in the mix of generation. Lesser risks arise from floods, droughts and an increase in peak demand". "The cost to energy networks from climate change is estimated to be $2.5 billion over the next 5

[17] Derived from 1 minus the emissions ratio, the E ratio being equal to (1-66/100) x (1-15/100) x (1-30/100)
[18] Derived from 1 minus the emissions ratio, the E ratio being equal to (1-50/100) x (1-15/100) x (1-30/100)
[19] ESAA submission on Exposure Draft of the Carbon Pollution Reduction Scheme legislation – 17 April 2009. See http://www.esaa.com.au/images/stories/policy_submissions/20090417cprsbills.pdf
[20] Energy network infrastructure and the climate change challenge – Feb 2009, see: http://www.ena.asn.au/udocs/PB-Report-and-Note.pdf

EMRI, 4 Baranbali Drive, Vermont South, Victoria 3133 Australia

Telephone: +61 3 9803 7170 Email: lasantha@bigpond.com
Mobile: 043 9803 717

years. The largest proportion of this cost arises from the requirement to augment networks to accommodate the increased use of air-conditioning". "A high level of investment is required to meaningfully reduce electrical losses. It is estimated that capital expenditure of about $1.2bn would be required to reduce electrical losses by 10%."

B.7.4 Future energy retailers will evolve to become energy service companies, more closely servicing customer energy requirements rather than the present predominant form of commodity trader. A good example of such a transformation under way is Osaka Gas[21]:

- Started business operations more than 100 years ago in 1905
- Serving 6.8 million natural gas customers in the Kansai Region (27% Japan gas market share in sales volume)
- Managing 57,800km of transmission & distribution pipelines. Still expanding pipeline networks
- Imports 7 million tons of LNG annually (approximately 5% of world traded volume)
- Participation in upstream projects in Australia, Indonesia, Oman and Norway; and holds interest in LNG carriers
- Developing power business as 2nd core business. Osaka Gas formed a power marketing company "ENNET" with Tokyo Gas and NTT. ENNET is the largest independent power marketer in Japan.
- 1, 390 MW cogeneration systems installed at 2, 210 locations in Kansai region
- Installed capacity of gas-fired air conditioners total 3.23 million RT

Local companies like Origin and AGL have followed similar models, but of late seem to favour alignment with 'centralised power generation' model rather than the deeper involvement with 'customer energy applications' model.

C Specific comments on the Draft Report

C.1.1 AEMC's findings and support reasoning starts with the following definition of demand-side participation (DSP) in the NEM

"ability of consumers to make decisions regarding the quantity and timing of their energy consumption which reflects their value of the supply and delivery of electricity."

Two comments are offered to improve the benefits we can draw from this exercise:

If all attempts to improve complicated processes concentrate only on one item at a time, we will have optimal sub-sets but for ever we will be left with **sub-optimal complete systems**. As mentioned previously substantial technology progress in energy efficiency is now available, very substantial energy price changes are projected as a result of impending carbon trading scheme, and very substantial investments are

[21] See http://www.osakagas.co.jp/htmle/corporate.pdf

envisaged both by generation and network companies, that some cognizance of their effects are badly needed;

Second, in the current circumstances defining DSP only in relation to "energy consumption" is equivalent to doing only half the job entrusted. As shown in the previous chapters, **distributed co-generation from gas** is expected to be cheaper than electricity from even coal power stations, so DSP must cover customer choice of: whether to use electricity form the grid, whether not to use electricity from the grid and whether to export electricity to the grid.

"The type and extent of barriers to the efficient and effective use of ***DSP*** *in the NEM depends on the definition of DSP".*

C.1.2 Analysis of the role of regulated network businesses.

The Draft Report is correct in stating:

"Network businesses: - investment by network businesses is generally driven by the need to build sufficient network capacity to meet peak demand (with an acceptable level of redundancy for unexpected contingencies). It is therefore ***peak demand that drives costs*** *– even if for most of the time the network has surplus capacity."*

The above statement aligns well with theory and practice in electricity pricing, only the wording sounds ambiguous. Peak demand is a driver for cost allocation but the costs do not vary with change in demand. Network costs are mostly sunk costs, but that said actual costs will vary by interest rates, which is variable external to the industry. Key cost drivers and to which part of the power system they apply are given in table below:

Cost Driver	Generation	Networks	Retail
Energy (KWh)	XXXXX		
Maximum demand (KVA) (sometimes KW and generally KWh for small customer not having demand meters)		XXXXX	
Customer numbers		(X)	XXXX

Customer numbers are relevant to the Networks, mainly to the distribution network - because costs connected with service connection, meter reading, billing, call centres, etc depend on the number of customers. Customer numbers have little relevance to transmission costs, the exception being the need to locate grid substations close to customer load centres. Customers directly connected to the transmission system, is another story, but the numbers are small yet the costs of servicing them are much higher than for other customers and therefore has to be assessed separately. SECV used a system of customer weights to adjust customer number based cost allocations, to recognize cost influences from factors such as level of customer dispersion, size of the service connection, penetration of gas mains supply, etc.

The fact that network tariffs still have a high proportion of cost recovery based on energy consumed, is more a failure to restructure legacy tariff component breakdown (force fit of old time-of-use tariffs that had high peak energy rates so as to establish a big price differential between peak and off-peak rates) than based on rational pricing theory. Vertically integrated utility style time-of-use tariffs with large price differentials necessary to incentivise customer response is not feasible in the current industry structure where pool price (constituting more than half of the total bill for larger customers) goes to the generator and the network charge flowing on to the network is much less than half of total bill for larger customers. Ideal network tariffs should have a small fixed component to cover customer related costs and the bulk of the cost recovery through contract KVA or contract KW demand tariffs. The contract demand is generally preferred, in that it forces the customer to do a proper evaluation when applying for supply and to be more circumspect when needing to increase the contract capacity. In the case of small customers, the demand component could be estimated from the rating (size) of the service connection and converted preferably to a fixed charge (network needs to reserve that level of line capacity even when the customer is away for couple of months and there is no marginal change to network costs). The optimum cost allocation factor is the customers demand contribution at the time of the distribution system peak demand, requiring a diversity factor to be applied to the customer's maximum metered demand value.

In view of the above, I strongly disagree with the statement in the Draft Report *"Network charges accurately reflect costs, and that these cost 'signals' are in turn communicated to individual users."*
A 2005 study of electricity pricing in California[22] by Charles River Associates examined the impact of several time-varying pricing rates:
"*One of these was a **time-of-use (TOU) rate**, which charged higher prices during peak periods when it costs more to procure electricity and lower prices during off-peak periods. Another rate was based on **critical-peak pricing (CPP)** that resembles a TOU rate on most days but on 12 summer days and three winter days, it charges much higher prices during peak periods. These high-priced days were called on a day-ahead or day-of basis, to simulate dynamic or real-time conditions that might be encountered when the power system goes critical, as it did in the Western States power crisis of 2000-2001.*

CRA found that residential customers in California will reduce their peak period energy use by about 5% in response to a TOU rate, which features prices that were about twice as high as the standard price of 13 cents/kWh, and about 15% in response to a CPP rate, which features prices that were five times as high."

As discussed previously, straight TOU rates for network tariffs are not suited to the current Australia industry structure. The interesting outcome of the above study was how well *critical-peak pricing* fared compared to TOU rates. A major draw back in critical-peak pricing is that the utility does not know **what is the price that will provide just sufficient response to clear a specific congestion situation**. Another

[22] Electricity Pricing Study in California, Boston April 8, 2005 given at: www.energy.ca.gov/demandresponse/documents/%20group3_final_reports/2005-03-24_SPP_FINAL_REP.PDF

draw back is that there is usually an upfront commitment fee which may or may not be effectively utilized.

The airline industry, a highly capital intensive industry like the electricity networks, has been very successful with using **reverse auctions** to increase yield. Reverse auctions are auctions where the bidder is the seller and not the buyer. The bid reflects how much the buyer is being asked to pay. The airline knows that certain percentage of customers do not turn up to fly as stipulated in the ticket, so they regularly overbook according to their best forecast of passenger numbers that will turn up. Occasionally there are more passengers than there are seats. So the auction starts with the airline offering an increasing sum of money until sufficient number of passengers volunteer to cancel their booking for that flight. Unscrupulous airline operators have been firmly reminded by regulators that the model is valid **only if there is voluntary cancellation**.

The **Opportunity Power** ™ technology package described above provides a two part capability, **first** a facility for the customer to access the full benefit of the pool price excursions. This is by using a specified energy quantity – price schedule broken down to half hours corresponding too pool settlement periods plus exposure to the pool price for any energy variance including export to the grid. The retailer servicing the customer is benefiting because the troublesome volume risk has been eliminated and any response by the customer that contributes to pool price being reduced (through reduced aggregate demand) would lessen the impact of the retailer's residual pool price exposure. Able to access the high pool price excursions with minimum pool price risk exposure is a major draw for the customer.

The **second** part of the package provides a single platform for a reverse auction process by any one or more of the following parties:

- the network operator faced with a network congestion, and / or
- NEMMCO faced with a market shortfall or faced with a need for constrained dispatch, and / or
- the retailer who is under hedged or exposed to volume variance due to extreme events.

The **Energy Arbiter**™ part of the technology package will enable the customer to not only benefit from opportune shedding of loads covered by the rate-quantity schedule, but also to use the in-house generator output to derive still higher financial gain.

Given that the Energy Arbiter™ provides electricity with high conversion efficiency and emits much less Green House Gases, it enables multiple financial benefit streams from different markets. Having multiple bankable income streams, the customers should be able to arrange the necessary plant and equipment to be installed on a income stream farm-in basis, where ownership and maintenance of the plant and equipment is under taken by the farm-in party. This would be a boon for vulnerable customers who otherwise find it difficult to finance energy saving facilities.

"*The desired outcome is for DSP to be used when the associated savings in supply-side costs is greater than the loss of value to consumers from using less electricity.*

EMRI, 4 Baranbali Drive, Vermont South, Victoria 3133 Australia

Telephone: +61 3 9803 7170 Email: lasantha@bigpond.com
Mobile: 043 9803 717

By extension, we want regulatory frameworks that support opportunities for efficiency-improving use of DSP to be identified and taken up."

The first part of the above statement may be true under the existing paradigm but has no place in the new paradigm - where demand side participation is driven by much higher incentives than from difficult establish (from the customer point of view) cost savings in the network. Pseudo assumptions of customer values are no match for actual testing of customers response to offers made for load curtailment via a reverse auction. The second part of that statement is spot on and vindicates the content of this submission. Every assistance will be provided to the AEMC or it's nominated party to make a comprehensive evaluation of the technologies described, so that AEMC can make an informed assessment.

C.2.0 Network Regulation objectives and drivers

As part of the electricity industry restructuring process, the networks were considered natural monopolies and that the competition model was not appropriate. The regulation regime for the networks was supposed to simulate market outcomes where ever possible. Considering public perception that networks had been 'gold plated' under the monopoly integrated utility model, there network assets were first optimized on the basis of replacement with current technologies / costs to arrive at an optimized replacement cost, which was then adjusted to reflect remaining economic life. This provided the initial regulated asset base also called Depreciated Optimized Replacement Cost (DORC). The regulatory regime was expected to scrutinize all new capital investment in the network and only allow addition to the regulated asset base if convinced that it added to the performance capability of the network. The veracity of the regulated asset base was to be tested by periodic application of the DORC process. Unfortunately the network regulators have shied away from using this audit process originally intended.

By now each jurisdiction has had about 3 Regulatory Reviews, where the Capital Expenditure and Operating Expenditures are reviewed. At each of these reviews, there was an expectation that some of the capital expenditure would result in reduced operating expenditure and improved performance. If what was promised in each of these 3 reviews was actually delivered we should have a much better network system than what we have today. Also we should start to see the capital investment reducing with time as more and more of the network was replaced / refurbished. Unfortunately, the performance record has not live up the expectations. It is suggested that DSP can play a very significant role in altering the regulatory approach, specially in the case of the distribution network where much of the DSP will interface.

C.2.1 Transmission and Distribution Networks are different

Power system comprises both the transmission and distribution networks, starting from generator dispatch connection point to the customer delivery connection point. The interface between the two networks is the intermediate connection point usually at the lower voltage bus bars of the transmission grid power station. The management of the reliability and security of the transmission power grid is the responsibility of the National Electricity Market Management Company (NEMCO), while reliability and security of the distribution system is the responsibility of distribution network owner / operators.

The transmission owner is responsible for preparing load forecasts in consultation with NEMMCO, with distribution network owners connected to relevant part of the transmission system and customers / generators connected directly to relevant part of the transmission system; for network augmentation and maintenance; and for operation of the network under NEMMCO instructions. The transmission owner is also responsible to inform NEMMCO of the safe operating conditions for the transmission plant and equipment, and to provide a forward plan for maintenance that require plant and equipment disconnection. The approach was different for the Victorian Transmission System as a whole, in that there was separation of ownership and network augmentation planning. VenCorp was entrusted the role of network planning and initiating capital works projects, which was then subjected to open tender on a Build & Own basis. This 'split role' model was widely accepted as being superior to the traditional owner / manager model for other transmission entities.

NEMMCO has many resources to manage the reliability and security of the transmission power grid. First option is that there is a market clearing demand and supply every 5 minutes. NEMMCO has the power to 'Direct' a market participant to take a particular course of action aimed at resolving a current or pending shortfall in capacity or reserves. The part of NEMMCO's work that is specific to network security is the maintenance of reserve capacities to meet contingencies. As market manager, NEMMCO does this by specifying reserve requirements and keeping the market informed through a series of cascading notices. First there are the market forecasts which include:

- Statement of Opportunities – a 10 year forecast of demand for electricity, capacity of existing and committed generating plant, inter-regional transmission capabilities, and advice on the impact of technical limits on sections of the network, forecasts of ancillary service requirements, minimum reserve levels, and economic and operational data. Also incorporates an Annual National Transmission Statement to provide an integrated estimate of the current state and potential future development of major national transmission flow paths;

- Projected Assessment of System Adequacy (PASA):
  - MT PASA for 2 years updated by 2:00 pm every Tuesday
  - ST PASA for 7 days updated 2 hourly from 4:00 am

- Pre-dispatch Forecast: estimate of price and demand forecast for the next trading day

Then there are ad hoc Reserve Notices drawing attention to forecast lack of future reserves graded according to level of expected reserve shortfall. And if matters are still not resolved NEMMCO has the option of using the Reserve Trader provision and / or the Power of Direction.

It is unfortunate that the Distribution Networks almost always attempt to rectify network capacity shortfalls with:

- increased investment in hardware part of the network, including voltage support and switching, at high cost and time;
- increase metering, communication and control / switching facilities to better use existing assets, which process (also called Smart Grid) is still more expensive.

The distribution system invariably contain parts that are serviced by single spur lines with no provision for back-up switching like in a ring-main system.

Opportunity PowerTM and Energy ArbiterTM will turn things around, to give the CustomerGrid – where customers will directly contribute to investment in new generation facilities, help manage power system demand, contribute to resolving power system constraints and take an active part in the control of energy market outcomes. Detailed economic analysis is not needed to work out that CustomerGrid is a far superior solution than Smart Grid, and provides superior multiple benefits like improved overall energy efficiency, reduced greenhouse gas emissions, reduced line losses, increased reliability for customer and to the power grid, reduced investment requirements, more transparency, improved energy market outcomes – the list goes on and on.

C.2.1.1 Tasmanian innovation can improve Distribution Network performance

In the 2003 Distribution Price Determination the Tasmanian Energy Regulator[23] agreed to a performance enhancement offer from Aurora, that involved portable generation to be owned by the distribution business and used in emergencies at remote locations and to facilitate planned maintenance. The Regulator's conclusions and how he incorporated expected outcome into performance targets, are very relevant to the question of facilitating DSP in the NEM

Enhanced Services Options Revised Estimates April 2003

Project	Total Cost $m	SAIDI minutes avoided	$ per SAIDI minute avoided
Portable generation	0.75	13.00	57 000

"As discussed in Chapter 3, each of the performance improvement options appear to represent good value for money for customers in that the capital cost of implementation in terms of cost per minute SAIDI avoided, are $114 000 (portable generation), $125 000 (feeder protection upgrade) and $215 000 (remote controls). Annual costs for these programs increase to total $400 000 by 2006, representing costs of about $10 000 per minute avoided SAIDI if the programs deliver the performance improvement forecast by Aurora."

"The outcomes of the customer value study, as described in the report, are that customers, on average, would appear to be prepared to accept an increase in annual bills of about 2.5 per cent for a reduction in outages of 20 per cent. This may be quantified as a customer aggregate willingness to pay of about $250 000 per minute reduction in SAIDI (assuming that customers ascribe a value to time without supply

[23] See:
http://www.energyregulator.tas.gov.au/domino/otter.nsf/LookupFiles/R_ElectPriceInvest_FinalReport.pdf/$file/R_ElectPriceInvest_FinalReport.pdf

in the same scale as they value the loss of supply). This conclusion should be treated cautiously, as it is expected that the performance improvements will be delivered primarily in areas that currently experience poor performance and the majority of the customer base would be contributing to significant performance improvements for relatively few customers. The question of a customer's willingness to pay for another customer's improvement in performance was not posed in the customer value study. Nevertheless, on the basis that the proposed performance improvements are generally considered to be equitable, this value is a guide to the benefit from performance improvements. Hence it appears that customers' willingness to pay is many times the costs of the improvements."

"The full reduction for the enhanced cases has not been used since it was deemed inappropriate to penalise Aurora for not achieving the full benefit of the enhanced scenarios. The Regulator decided that Aurora should be expected to achieve 50 per cent of the projected improvement from the protection upgrades, 100 per cent of the improvement from the remote switching and 100 per cent from the introduction of portable generators."

What this exercise demonstrated was that dispersed small scale generation is valuable to the distribution network and can improve network performance significantly. Although the Regulator accepted the Aurora proposal to invest in portable generators on the basis it provided the customers, value for money, he raised a very valid question. "*The question of a customer's willingness to pay for another customer's improvement in performance was not posed in the customer value study*". There is also the market research finding that customers perceive receiving a dollar payment as being better than saving a dollar on their bill.

Looking at this exercise in the light of technology package for distributed co-generation from gas as described above, if the customers were able to provide the electricity when needed by the distribution network, the network would not have to incur capital expenditure on equipment that had very low utilisation, the operating cost of the mobile generator is saved, and also very significant in the current global warming scenario, there would be significantly less GHG emissions. The Regulators question would be redundant since customers would be responding to their own choice of intervention price if there was a reverse auction as proposed in the technology package. Considering the extremely low utilisation factor and the cost of diesel fuel for the generator, the opportunity cost to Aurora could well be over $ 1 per KWh, which many a co-generation customer would find very attractive. Yet this is only one tenth the value of lost load ($10, 000 per MWh or $ 10 per KWh) used for capital investment justification, which then needs to be translated to a realistic marginal incentive (bonus / penalty) by the regulator.

This is consistent with the need for a transparent regulatory control mechanism for ensuring security / reliability of the distribution network.

C.2.2 Distribution Network Regulation must provide for explicit security / reliability management processes

In the late 1980s EPRI had a project to develop the parameters for Priority Service Methods (PRISM). The concept was that by offering customers the choice of different "qualities" of electricity at different prices, the value of electricity service may be increased to all customers. In practice utilities had little capacity to increase the level of reliability to particular customers, but had more leeway to reward customers to surrender their right to the 'common' level of reliability by means of curtailment rates / incentives.

Network charges in rural areas are a larger part of the electricity bill due to the longer lines needed to service them. As their augmentation is partly based on the value those customers place on reliability, the design level of reliability is low in rural areas. Also regulators tend to set a lower level of reliability when mandating minimum service standards for such areas. Often cost of supply studies that show large cross-subsidies to rural areas fail to correctly reflect this variation in service reliability levels.

Networks are not the sole contributor to the cost of reliability in electricity supply. The NEM is based on a 0.002% level of reliability in the supply of electricity to the wholesale market. This standard of reliability is very far removed from the level of supply reliability available in rural areas, or even available to small business / residential customers embedded in the urban distribution network. To these customers it makes no economic sense to pay for an extremely high level of reliability for wholesale market energy that cannot be delivered at comparable levels of supply reliability. One way to overcome this anomaly is to expedite introducing facilities for demand side response that provide means to sell back undervalued components like reliability, as provided via the combined technology package described above.

Power system reliability generally refers to generation and transmission systems (because of NEM), and is a measure of the ability of the system to supply energy to meet the load. But most of the load is embedded in the distribution system yet there is scant attention to managing supply reliability in the distribution system. In general, Regulators have been snug in concentrating on performance measures such as:

SAIDI - System Average Interruption Duration Index
SAIFI - System Average Interruption Frequency Index
CAIDI - Customer Average Interruption Duration Index
MAIFI - Momentary Average Interruption Frequency Index

Calling these 'reliability measures' is like keeping count of air craft collusions, which in reliability studies parlance is counting the 'collateral damage'. In air craft reliability studies the critical event is when the **aircraft collusion envelopes overlap** due to loss of control of aircraft energy. This critical event is termed a '**near misses**" and is considered to have occurred when two or more aircraft are within a defined horizontal (1Nm) and vertical (500 feet) limits without being aware of each other's presence.

From transmission reliability studies we know that the 'critical event' (loss of control point) is when interfering object penetrates the conductor flashover envelope. This covers movement of conductors relative to each other, line sag due to high currents and / or high ambient temperatures, compounded by the effect of line sway in high winds, etc. etc. Transmission owners / managers are supposed to inform the system operator (NEMMCO) of safe operating conditions of their plant and equipment including updates if ambient conditions change. NEMMCO uses such information on a deterministic manner to arrive at requirements for secure operation and the required reserve levels to meet credible contingencies. Changes to previously published conditions are provided as updates to market participants.

A rare instance of a regulator taking cognizance of a true measure for reliability control (a near miss situation rather than consequences of poor reliability) was Performance Reports by the Tasmanian Energy Regulator. These reports include performance of distribution feeders classified as 'firm' but which had continued in service in a 'non-firm' condition, gives the number of times this happened and the aggregate time this condition continued. Given the large investments involved and the peaky nature of electricity demand (extreme hot or cold weather conditions) it is not uncommon to find many distribution systems go 'non-firm' on extreme weather days. According to the 2008 Reliability Review Report[24] by the RNPP of the Office of the Tasmanian Economic Regulator, Aurora had 7 zone substations and 62 HV feeders exceeding their firm capacity. The Tasmanian Economic Regulator is to be commended for publishing such information on a regular basis, something that should be made mandatory by all state regulatory bodies / AER.

A proper reliability system for distribution networks must, like in the case of NEMMCO, publish information on network constraints specially shortfalls in secure capacity of respective lines and times they are occurring or are forecast to occur – the distribution system version of Projected Assessment of Distribution System Adequacy (PADSA) Report. This public document (updated on a regular basis) should also indicate a minimum (base) payment the Distribution company will undertake to pay for energy from embedded generation exported to the relevant distribution grid area within respective shortfall intervals. The distribution company must also stipulate the maximum amount it will bid through a reverse auction to clear that deficiency in that period. This is the crucial point (network regulation simulating market outcomes) where regulators can verify the validity of customer value imputed by the Distributor when justifying capacity augmentation. Given that spur lines are by definition not secure, the report for spur lines should contain information on the 'safe working load' (SWL) for the line and actual maximum load for the last 3 years. Such data will provide guidance on the potential for exceeding SWL of the line and other plant elements, specially under very hot ambient conditions (when multiple hazards converge, eg. high ambient temperatures reducing cooling effect, high customer loads due to air conditioners and the combination of high ambient temperature conditions and high loads increasing the sag of network line spans).

The above discussion provides the groundwork for reviewing the Draft Report sections under the heading Mechanisms for managing reliability. Hopefully the discussion informs on statements like:
"network planning standards which are based on economic values of reliability".

---

[24] See:
http://www.energyregulator.tas.gov.au/domino/otter.nsf/LookupFiles/Reliability_Review_2008_Final_Report_March_2009.pdf/$file/Reliability_Review_2008_Final_Report_March_2009.pdf

EMRI, 4 Baranbali Drive, Vermont South, Victoria 3133 Australia

Telephone: +61 3 9803 7170 Email: lasantha@bigpond.com
Mobile: 043 9803 717

"We also note that probabilistic planning standards are likely to be more consistent with efficient use of DSP because they appear more amenable to handling DSP with different degrees of 'firmness'."
"Efficient DSP is likely to involve aggregation of individual loads by specialist intermediaries"
"potential significance of small-scale, on-site generation as a contribution to DSP"

Agree completely with the statement:
Existing processes by which small-scale generation can be connected (or recognised) by DNSPs are therefore important. The processes currently lack consistency and transparency.

Disagree with the statement "*A key finding is, therefore, that supplementary bilateral contracts for DSP between network businesses and individual consumers can improve efficiency by 'plugging the gap' left by imprecise network charges*." As discussed and according to the proposals made above, it is suggested that open type market operations suggested above is a far better process than the difficult to negotiate, case by case, secretive and often inadequate individual contracts. The suggested open market type systems better emulate market outcomes expected from regulated entities.

"This prompts the question of whether network businesses have the correct incentives to buy DSP when it is efficient to do so". The first step to determine efficiency would be to look at the need to buy and the time / quantity of the need. The suggested publication of the **Projected Assessment of Distribution System Adequacy (PADSA) Report**, covering both secure lines and spur lines, is essential for establishing an informed market (criteria 1 of an efficient market). The crucial question is the price at which the distributor offers to purchase the generated electricity. To be consistent with regulatory decisions that allow substantial capital investment on the basis of imputed customer values for lost load, that same number (imputed customer values for lost load) should be the cap for the purchase price offered by the Distributor, since a shortfall in network capacity is tantamount to a failure to deliver as per regulatory contract. The second step to determine efficiency would be to look at the options / alternatives or possibly the 'avoided cost', which is looking back on what was paid to provide the service according to the regulatory contract.

If one accepts the efficacy of the incentive approach to performance improvement, DSP payment by the poorly performing distribution business would stave off having to pay the penalty, and because the incentive / penalty values are congruent, the distribution businesses that are doing well will also benefit from engaging with DSP proponents. So the distribution should engage with the DSP customers from the start of the regulatory period itself without waiting to fix a looming penalty towards the end of the regulatory period. Although the size of the incentive component started off on a low key, the stated intention was that it will be made larger as the distribution companies gained more experience with them. Monies paid to discerning customers that result in improved performance to all customers helps put financial pressure on 'free riders' whose excessive consumption at peak times puts pressure on service level and prices to all other customers.

Strongly disagree with the statement:
"Our analysis demonstrates that a network business that is regulated under a price cap has private incentives for buying DSP that are consistent with socially efficient levels of DSP."

The whole intent of regulation is to set conditions that will align private company motivations with intended socially efficient outcomes, without which or with lax enforcement of conditions to that effect, the private company will go about doing its main business, ie make profit. We must remember the distribution network is a monopoly service, so up to now the customer had no other option. If the network had two options, one to pay the DSP a fair price and increase social welfare and the other not pay the DSP, forget about social welfare (as there is no mechanism to enforce it) so that it can make more profit, no prize is needed to working out the correct answer.

The notion that the networks are regulated on the basis of a 'price cap' is s furphy. What the regulators actually do is start with the regulated asset base, determine the allowed rate of return and with the network nominated capital depreciation rate - to work out the capital charge on the business (largest component by far). The allowed operating expenses and the allowed capital expenditure are added to the capital charge to arrive at the revenue cap from which comes the price cap. We are talking of a capital intensive industry with asset lives extending to around 50 years, the capital invested in the business is very high. As the regulator allows the company to set the depreciation rate (on the mistaken belief the company will not take out too much as it will reduce future returns) the company is happily taking out lots of money and at the same time trying to make it up by substantially increasing the capital expenditure budget. To break this vicious cycle, it will be necessary to make it possible for the customer to substitute customer's own facilities to serve the same distribution outcomes, instead of being tied forever to a monopoly gold plated money maker. No wonder the network businesses had plenty of interested buyers whenever they came up for sale, in spite of the seemingly incongruous notion of a regulated asset base – which formed the basis for the regulated returns that were allowed under the Code.

Disagree with the following statement for the same reason as above:
"The reduction in revenue experienced under a price cap serves an important function in making sure that the network business has full regard to the loss of value experienced by the DSP provider whose load is curtailed under a DSP contract."

The implied story behind that statement is that there would many more customers who are more badly affected by a power outage than the customer agreeing to a DSP contract, and they are likely to want much more than the lowest impact customers who are likely to sign up first. With the benefit of a technology package as described above, much more customers will become available for DSP, as they now have the triple option of shedding load, running the onsite generator, or doing both load shedding and electricity export by running the generator.

Further, as we saw under the Tasmanian example of the Aurora operating mobile generators, "the opportunity cost to Aurora could well be over $ 1 per KWh, which many a co-generation customer would find very attractive" but I still have to find a distributor willing to payout that much for DSP.

EMRI, 4 Baranbali Drive, Vermont South, Victoria 3133 Australia

Telephone: +61 3 9803 7170 Email: lasantha@bigpond.com
Mobile: 043 9803 717

"The current method for re-setting network prices or revenue allowances appears to penalise a business who in the previous regulatory period decided to use expenditure on DSP as a means of deferring capital expenditure."

The above statement implies that DSP is a passing fashion, and the network needs to continue building bigger and bigger networks. There are a number of other scenarios that are more relevant. First, that DSP is the future. In which case, following an initial acceptance period, the customers will be setting up DSP on their own account, without being a drain on the distribution network. Where the DSP takes the form of technology package mentioned above, the customer still needs the full network capacity either as a user of electricity or as an exporter of electricity. When the technologies are well established and the tariff restructuring is complete, further extension of DSP should have minimum impact on transmission network revenues. The expansion of the distribution network may eventually level off, unless more industry load was to develop which will draw more of the low cost electricity from distributed co-generation using gas.

"limited financial incentives for network businesses to innovate under the current forms of revenue regulation are likely to act as a barrier to such businesses making appropriate use of DSP. We consider that explicit 'use-it-or-lose-it' funding for innovation, for a limited period of time, might be a proportionate way of addressing such a barrier."

It is also possible that the network businesses, not being geared to do the tasks required, would prefer not to get involved unless they have to – which means the penalty has to be greater than their threshold for financial pain. It is also possible that the DSP models on offer were not convincing or seemed to usurp their business profitability. If the distribution businesses were to re-evaluate their business model to include rental and maintenance of the DSP systems like the implementation options for the technology package described above, (much like some oil companies redefining their core business to be energy rather than oil), it will ensure their businesses will continue to grow, through non-regulated service offerings.

C.2.3 Key to maximising allocative efficiency

Allocative efficiency*[25]: Maximising allocative efficiency involves allocating resources to their highest-valued use given existing technology at a given point in time. When prices are efficient, resources tend to be directed to those who value them most (as expressed by their willingness to pay for them). The concept of allocative efficiency places an emphasis on the choices made by decision-makers in response to the prices they confront; if prices do not accurately reflect costs, then the choices made by individuals may lead to an inefficient allocation of resources. In the NEM, for example, spot market pricing signals are highly relevant to the delivery of allocative efficiency at times of very low generation reserve levels. In such situations (typically accompanied by increased spot prices and/or supply curtailment)* ***allocative***

[25] Assessing the efficiency impact of proposed changes to market arrangements – Guideline By NEMMCO (27August 2002)

EMRI, 4 Baranbali Drive, Vermont South, Victoria 3133 Australia

Telephone: +61 3 9803 7170 Email: lasantha@bigpond.com
Mobile: 043 9803 717

efficiency is enhanced if market arrangements facilitate voluntary load curtailment by customers, in response to diminishing reserve levels and rising spot prices. *Where voluntary responses to supply shortages are facilitated, the available (reduced) supply will continue to be consumed by those who value consumption the most.*

In the late 1980s EPRI had a project to develop the parameters for Priority Service Methods (PRISM). The concept was that by offering customers the choice of different “qualities” of electricity at different prices, the value of electricity service may be increased to all customers. In practice utilities had little option to increase the level of reliability to particular customers, but had more leeway to reward customers to surrender their right to the ‘common’ level of reliability by means of ‘curtailment rates’ / incentives.

Outage cost (also called Value of Lost Load or VoLL) studies have established that an outage with prior notice creates less problems to customers than unannounced interruptions. It has also been shown that different customers place different values on supply outages. Figure 6 gives the customer class average values for lost load, which are taken from a study done by Monash University[26] for the Victorian Power Exchange and later extended to cover other states as well. These studies formed the early basis for setting the pool price cap in Victoria and in the NEM (pool) as well.

Also around the time VoLL studies were being conducted by Monash University, the Electricity Supply Association of Australia (ESAA) constituted an expert working group to develop a Guide for Reliability Assessment in Network Planning. The Guide[27] provided typical values for demand and energy costs of interruption that was somewhat close to the findings from the Monash study.

Estimates of Value of Lost Load for different customer classes

Customer Grouping	Monash Study (Victoria)	ESAA Guideline (Medium case) Demand Component	Energy Compt
	($/kWh)	($/kW)	($/kWh)
Residential	0.7404138	0	6
Commercial	75.958978	1	20
Agricultural	96.198087		
Industrial & major user	11.193920	2	8
Central Business District		6	20

The Monash study involved a stratified customer survey with responses from over 1,100 residential customers and over 2,000 business customers. The survey responses were matched with actual customer billing data to derive weightings. Results of similar studies[28] done in the USA, UK and Canada seem to be closer to the Monash study results than the ESAA figures.

[26] Value of Lost Load – Study for Victorian Power Exchange by Dr M. E. Khan, Monash University Aug 1997
[27] Guidelines for Reliability Assessment Planning – ESAA 1997
[28] See also Customer Demand for Service Reliability – A synthesis of the outage cost literature (EPRI paper) September 1989

EMRI, 4 Baranbali Drive, Vermont South, Victoria 3133 Australia

Telephone: +61 3 9803 7170 Email: lasantha@bigpond.com
Mobile: 043 9803 717

A point worth noting is that the Monash study indicates that residential customers place a very low value on lost load compared to all other classes, being one hundredth of the value placed by commercial customers. The average aggregate value of lost load derived by the Monash study was 28.9 $/kWh, which was comparable with the values obtained by Kariuki and Allan in their 1995 study[29] of customer outages costs in the UK. There is a major problem in using aggregate values to drive investment for reliability improvement, as most business customers value reliability more than the average aggregate value that sets the delivered level of reliability (so are dissatisfied with the outcomes) while on the other hand most residential customers place much less value on the delivered level of reliability, so end-up paying more than they ought to.

The inference we can draw from the above is that seeking load shedding from only large customers (they are easier to manage because few customer can give large load reductions) on the basis of transaction time and cost , is misplaced as it will be counter to the main objective of improving allocative efficiency. With the new technology package, we are able to overcome the transaction cost / time / verification constraints so that DSP from large customers is no longer the preferred option. The advantage is further reinforced by the capability for reverse auctions, which means that the process goes step by step until the required level of load reduction is obtained. This process may be too difficult for big customers but is easily accommodated by a large number of small customers, the process considerably helped by the diversity inherent in very large numbers of small customers.

D 1.0 DSP and the Wholesale Market

To appreciate the potential for improving market outcomes offered by DSP in general and DSP using the technology package described previously, the comments will first re-iterate the features of the technology package that provide it a comparative advantage in interacting with the pool type energy market; then go on to look at the objectives of electricity industry restructuring and the principles governing pool market design. The last part of the commentary is concerned with options possible for making a contribution to improved market outcomes and any changes to the rules that might be desirable.

D 1.1 Features that interact with the pool type energy market

The cornerstone of the technology package described above is its ability to operate in a pool type energy market. The package uses a derivative to gain exposure to pool price excursions with protection for a contracted level of consumption. There is no negotiation needed since the customer can provide a staggered response according to threshold triggers for shedding different loads or exporting different levels of energy, as the prices offered escalate in the reverse auction process. The package has a common platform to accommodate price premiums offered by the network, by

[29] Evaluation of reliability worth and value of lost load by K K Kariuki and R N Allan in IEE Proc – Gener. Transm. Distrib Vol 143 No 2 March 1996

NEMMCO, or any other party and the response is time stamped because of the included smart meter. Because it includes an 'always on' communication system linked to the computer based control system, the response time is well within the 5 minute dispatch period.

Retail customer using the technology package will have smart metering and always on communications. The metering database can easily tag these customers, so that their meter readings can be accessed easily. The package involves computer control of package facilities and provides very fast response, well within the 5 minute market rebalancing / dispatch pricing solution. The unique customer meter code incorporating zonal codes can be used to channel price premium offers only to customers in particular zones. Accommodating an internet poll enabled database of 5 minute meter readings is also possible. The in-premises generator is connected to the mains supply via an inverter, as such it has inherent capacity to also export reactive power into the mains power system.

Following demand side participation options are made possible:
- reduce load in steps according to pool market price exceeding price threshold for that set of loads;
- price premiums on offer from the distribution / transmission network operators increase the impact price enabling earlier crossing of threshold values for load shedding;
- price premiums can also be from NEMMCO or a load response aggregator;
- in addition to load reduction, generator operation can provide electricity export to the mains power system;
- because the mains connection is via an inverter, KVAr export is also possible with appropriate incentives.

D 1.2 Objectives and principles governing electricity market design.

The objectives of the electricity industry restructuring as enunciated in the Electricity Act 1996 and the Market design principles incorporated in National Electricity Rules are reproduced below to set-up a frame of reference for the ensuing discussion..

Electricity Act 1996
Sect: 3 Objects
The objects of this Act are—
(a) to promote **efficiency** and competition in the electricity supply industry; and
(b) to promote the establishment and maintenance of a safe and **efficient** system of electricity generation, transmission, distribution and supply; and
(c) to establish and enforce proper standards of safety, **reliability** and quality in the electricity supply industry; and
(d) to establish and enforce proper safety and technical standards for electrical installations; and
(e) to **protect the interests of consumers of electricity**.

National Electricity Rules
Section 3.1.4 Market design principles

(a) This Chapter is intended to give effect to the following market design principles:
(1) ***minimisation of NEMMCO decision-making*** *to allow Market Participants the greatest amount of commercial freedom to decide how they will operate in the market;*
(2) ***maximum level of market transparency*** *in the interests of achieving a very high degree of* ***market efficiency****;*
(3) avoidance of any special treatment in respect of ***different technologies*** *used by Market Participants;*
(4) consistency between central dispatch and pricing;
(5) ***equal access to the market*** *for existing and prospective Market Participants;*
(6) ancillary services should, to the extent that it is efficient, be acquired through ***competitive market*** *arrangements and as far as practicable* ***determined on a dynamic basis****. Where dynamic determination is not practicable, competitive commercial contracts between NEMMCO and service providers should be used in preference to bilaterally negotiated arrangements;*

We see that the primary objective of electricity industry restructuring was to promote efficiency in the electricity supply industry. The objective statement identifies the intended beneficiaries "to protect the interests of consumers of electricity". There would be no disagreement if one was to say - that any industry exists to serve the customer, but some times the industry is so big that dominant suppliers fail to appreciate how vulnerable they are if they were to disconnect from the customer - General Motors now facing bankruptcy is a good example.

Electricity pool market was established in the current form as it was considered at the time of it's institution, that a fully open two way market with both demand and supply bids was not feasible with the available technology and time. So the current form of the market was accepted as the next most efficient way to provide a safe and secure supply of electricity to customers. There is no dispute that an efficient market must provide equal opportunity for both buyers and sellers. As discussed earlier, retail customers can provide demand side response and since the wholesale market is linked in real-time to customer consumption of electricity, that very fast response on the part of the customer – now possible with the described technology package, can have an impact on the next market rebalancing at the end of the current dispatch period. The dynamic nature of this interaction is evident from the fact that it is not only the kilowatts of energy that is involved. First, when the market is facing a shortfall because of excessive demand, the line losses are also very high - given that line losses are a square of the current flowing. Second, as systems controllers are well aware, to push kilowatts through heavily loaded power lines, the reactive power losses are also very high, sometimes more than the kilowatts delivered. Accordingly, the kilowatt shed by the customer is more valuable than the kilowatt sent out from the power station.

Under normal operating conditions the Ancillary Services market is almost inconspicuous but at times of severe supply shortage, price in the Ancillary Services market also can go up to VoLL - meaning the market is failing it's function (to clear). Given we now have a mechanism for NEMMCO to add a price premium so as to incentivise more customer demand side response, it is suggested that the appropriate method should be for NEMMCO to open the Ancillary Services market (where possible) to customer participation. This NEMMCO can do by offering the same price as is offered to Ancillary Service providers as a price premium to enabled customers. Such a step is necessary to ensure that there is balance in the opportunities available to the supply and demand sides, which is an essential condition for an efficient market. It is well accepted that reverse auctions are more efficient (for capacity utilization in capital intensive industries) compared to competitive tenders, adding further increase in efficiency from use of the new technology package.

The National Electricity Rules is abundantly clear - that competitive commercial contracts for Ancillary Services is second best with dynamic determination as the preferred option, and competitive commercial contracts are to be used only if dynamic determination is not practicable. As explained above, with the new technology package, dynamic determination is practicable – maybe it will take some time for sufficient facilities to be installed but eventually it will provide a much better outcome to the customers and to market operations. Before industry restructuring, generators were loaded in a manner so that each generator could perform regulation services. That way large number of generating plants were able to respond instantaneously to a power system disturbance, which response was significantly better than having only a few generating plant trying hard to ramp-up output to meet capacity shortfalls due to a trip of a major generating plant or transmission line. Now dynamic response at the customer end can substitute for the lost dynamic response at the generator end. Since generators bidding into the Ancillary Market cannot serve the energy market at the same time, their capacity utilization is quite low. On the other hand the dynamic response by the customer using the new technology package is using a multimode plant, so the capacity utilization of that plant is much better and the energy conversion efficiency of the plant is also better than at a central power station. Thus overall efficiency is now better.

D 1.3 Options for contributing to improved market outcomes

The draft report is absolutely right in saying that DSP must include pool price benefits. The beauty of the proposed technology package is that in many cases where the distribution network requires network reserve capacity support, the pool price may be high enough to trigger sufficient customer response which will re-instate network reserve capacity. If the network wants more response, the network operator can add a price premium. The customer is already benefiting from the high pool price and with the extra premium will step up the response level. So effectively the outlay needed by the network may be small if it coincides with high prices in the pool market. If the network congestion / loss of reserve happens when the pool price is low, then an attractive enough premium needs to be offered in a step process made possible with reverse auctions. This also applies to 'out of merit generation dispatch' situations when a zone is impacted by constrained network access. If sufficient DSP was able to overcome the network constraint there is no need for out of merit generation dispatch.

The Longford gas plant failure illustrated the frustration the State Governments have when market procedures do not allow customers to self-disconnect at a high enough buy-back price, which very many customers will be willing to undertake (those with generation facilities can export part of the output or the full amount) for a payment, if it is organized in rotation. In the days of the SECV, there was always more than

EMRI, 4 Baranbali Drive, Vermont South, Victoria 3133 Australia

Telephone: +61 3 9803 7170 Email: lasantha@bigpond.com
Mobile: 043 9803 717

adequate customer response to advertisements in the newspapers and local radio - to say that problems in the Valley is threatening electricity supplies and appealing for customers to reduce their electricity consumption. That way SECV avoided the need for rolling blackouts over a period of almost a decade.

Customers equipped with the technology package can provide NEMMCO the following services:

- Frequency Control Ancillary Services;
- Network Control Ancillary Services;
- Introducing dynamic determination to Reserve Trader via reverse auctions would enable NEMMCO to restore adequate reserve levels within the 30 minutes period following a contingency event;
- Substitute for rolling blackouts, by offering premiums going up to VOLL, selectively target customers in affected areas, in rotation until underlying major contingency is resolved.

"In circumstances where the market does not deliver sufficient capacity to meet the desired reliability standard of 0.002 per cent average unserved energy, then NEMMCO can intervene to buy additional capacity or issue directions to existing market participants. These are additional potential markets for DSP."

"Inability for NEMMCO to compensate 'unscheduled' loads, even if they are capable of being directed"
Agree with the above statements contained in the Draft Report, but as described above the wide scale adoption of new technologies described above will provide alternate avenues.

It is important that the market has a mechanism for ***competitive market** arrangements (equal opportunity extending to customers as well)* ***determined on a dynamic basis*** to avoid involuntary load shedding, since involuntary load shedding would be **market failure**.

E Recommendations:

1 AEMC should institute a consultation process with electricity and gas industry participants, including coal seam gas exploration companies, customers and new duel energy use technology proponents,

- to assess and plan an optimum energy development and use strategy for Australia, consistent with the new amalgamation of electricity and gas industries under a single regulatory / management regime;
- to assess relative positions in the energy use efficiency chain from a national benefit perspective, as an input to sculpturing an appropriate regulatory regime to align national interest with participant companies regulatory performance interest;
- initiate necessary regulatory change processes accordingly.

2 AEMC should initiate a consultative process to review that part of the National Electricity Rules pertaining to the regulation of distribution businesses, giving special consideration to:

- provisions to monitor and control reliability of electricity supply within distribution networks, incorporating standard practices across all participating state jurisdictions be they state government owned or in private ownership;
- necessary provisions to ensure reserve margins and ‘firm supply’ will be maintained as per performance contract made with the regulator at the time of the Regulatory Review;
- reviewing the need to find market alternatives to current practices that depend on supply feeders and other plant tripping on overload protection;
- review the desirability of standardization and public disclosure of all reliability commitments by transmission and distribution bodies, since the capital and operating cost of the network is driven largely by such commitments;
- reviewing the need for jurisdictional priority order lists that bestow favoured status on particular users who fail to take adequate steps to bridge the gap between their reliability needs and the common level of reliability provided by the distribution network.

3 AEMC should update previous studies of available technologies for demand side participation in pool type markets, if necessary by commissioning an independent verification of the of new technologies described above, since their early utilization will have far reaching beneficial effect on industry development going forward.

4 AEMC should request NEMMCO (or its successor) to review whether wide scale adoption and use of the technology package mentioned above would affect the operations of the NEM (as presently constituted) and what changes would be needed :

  - in the package to avoid detrimental interaction;
  - in NER to benefit from the application of the package on a widely dispersed scale.

4 AEMC should initiate a comparative cost-benefit assessment of relative roles (sustainability, GHG emission reductions, cost, efficiency, job creation, public and customer sentiment, impact on the energy market, impact on network services, etc.) of renewable resources like solar and wind, (which are intermittent in nature and often needs transmission cost subsidies) versus role of co-generation and energy efficiency, which often can provide responsive electricity generation output without the low capital utilization penalty of peak generation plant. The assessment should include framing recommendations to the federal government on balancing assistance measures to get optimum outcome for all Australians.

Thank you for this opportunity to provide comment. I would be happy to provide further explanation / clarification on any of the matters mentioned above. My contact details are provided at the bottom of the page.

EMRI, 4 Baranbali Drive, Vermont South, Victoria 3133 Australia

Telephone: +61 3 9803 7170 Email: lasantha@bigpond.com
Mobile: 043 9803 717

Lasantha Perera

EMRI, 4 Baranbali Drive, Vermont South, Victoria 3133 Australia

Telephone: +61 3 9803 7170 Email: lasantha@bigpond.com
Mobile: 043 9803 717

Attachment A

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:

- demand side response in the context of the electricity pool market;
- retail pricing and value studies;
- distributed generation;
- network and ancillary services pricing.

Contact Details:

Lasantha Perera, Director
Electricity Markets Research Institute
4 Baranbali Drive,
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

September 2001 to January 2004, was Assistant Director at the Office of the Tasmanian Energy Regulator responsible for setting up the Performance Monitoring and Reporting section and providing technical advise to the Regulator. Also provided technical and secretarial support to the Reliability and Network Planning Panel responsible for setting standards for the Tasmanian power system and making recommendations to the Regulator on network investment proposals

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 from both the Electrical and Mechanical Institutes in the UK. Has over 35 years experience as an engineer / techno-economist, with work experience covering electricity generation, distribution, contracting, engineering jobbing, co-generation plant maintenance and R&D into renewable energy sources.

Under section 48 of the National Electricity Law, the AEMC has omitted information due to its confidential nature.