Comments on Draft Issues Paper: NEC Network Pricing Code Changes

Preface

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

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

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

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

This submission is done on a pro-bono basis following overtures from a couple of customer representative groups. Due to time constraints it has not been possible to get endorsement from these groups and as such the representative groups cannot be divulged at this time.

Introduction

It is fair to say that the NEM was largely modelled on the Victorian competitive market. At it inception, the Victorian ESI restructuring was confined to Victoria and started with the disaggregation of the integrated utility into three businesses – Generation, Transmission and Supply (including distribution and retail). Inter-connectors to other states (viz New South Wales and South Australia) were included with Transmission but only that portion of the inter-connector up to the Victorian boarder. With the establishment of the Vicpool market, the Opportunity Interchange arrangements were managed from within the Victorian Pool via resident Traders. Victorian Power Exchange or VPX (now Vencorp) was and still is responsible for the planning and operations management of the Victorian transmission system. The NEM which combined a number of such State markets, has still not come to grips with the new role for Inter-connectors so necessary to operate the integrated National market.

Role of End-use Customers

In 1997, I had the good fortune (thanks to my former employer – Eastern Energy Ltd, who covered my expenses) to meet and discuss regulation issues with representatives from OFFER, OFWAT, Customer Groups, Industry Associations, Consultants, Contractors and industry 'think tanks' such as the Centre for the Study of Regulated Industries. I found that Regulation in the UK Water Industry had the closest contact with the customers. OFWAT methodology started with measures of levels of service performance, developed in consultation with the representatives of customer groups (eg of a different approach to customer representatives appointed by NECA). Individual companies could negotiate with their customer representative groups a capital expenditure program to achieve mutually agreed service levels. Of course the water industry is not so complicated as the electricity industry, but this is all the more reason for establishing an early and meaningful dialogue with customers.

Deliberations within the NEM has so far been confined to matters connected with the Wholesale Market and have been among NEM participants with very little input from customers. Full contestability, including the mums and dads, is just over a year from now. Is the industry ready? Maybe. Are the customers likely to be ready? Maybe not.

Unlike the industry players, customer representatives lack the knowledge and skills to understand and debate issues that effect them. They lack the funds to engage high powered consultants to push their interests. The situation calls for foresight on the part of the National Market protagonists and the Regulators (State Regulators are to be commended for their efforts to develop good rapport with customer representative groups) to ensure the CUSTOMERS are included at least in the future. Recent Victorian election results and the Victorian ALP manifesto on the Electricity Industry are early warning signs of how things can come undone.

Role of Inter-connectors

As the NEM operates on the basis of Regions (nodes), an Inter-connector is defined as a connection between two regions. For historical reasons previous State systems were designated as a Region (ACT being included into NSW) except for the Snowy Scheme – which was designated as a separate Region. Again for historical reasons, the Inter-connectors happened to be whatever bits of line that had been initially built for other purposes. Problems that are now evident include:

a) need for augmenting of current inter-connectors
b) need for new inter-connectors
c) either augment intra-connectors in Queensland or divide the long and thin transmission system in Queensland into two or even three zones
d) question of whether Snowy scheme should be a separate zone on its own, eg why should Snowy get any Settlement Surplus when it does not have customers who pay the higher prices that create such a surplus.

Revisiting some Key Propositions in the NECA Report

In my view there are some key propositions in the NECA report that need to be revisited:

a) sunk costs of networks
b) need for price signals
c) full nodal pricing
d) Entrepreneurial inter-connectors and firm access
e) Victorian Cross Subsidies in 1989

a) sunk cost of networks

NECA report reiterates the position advocated by Putnam, Hayes & Bartlett – Asia Pacific Ltd (PHB) in their March 1998 report prepared for the National Generator Council, that while long run marginal costs (for new investment) should be the basis of economic signals to the market, there is no economic signalling role for 'sunk costs' of assets in current use. NECA designates 1 July 2000 as the date for applying a benefits ratio to allocate recovery of new investment in network assets between generators and final customers. I fail to see what is special about 1 July 2000 that those same assets that were deemed that day to be a 'new investment' have not become a 'sunk cost' on the very next day - 2 July 2000; whereas this happens every day up to 1 July 2000.

PHB and NECA seem to have missed the point that Optimised Depreciated Replacement Cost (ODRC) or any of its variants was designed to precisely overcome this problem. Each and every time ODRC is performed it comes up with an asset value that truly represents the long run marginal cost of servicing the then current network requirement with the optimised set of best of breed network assets. ODRC can be considered as the 'transformation' of a historical asset mix at historical asset values, to the latest estimate of long run marginal cost. This being so, there should be no difference in the treatment of existing assets and new assets, and the principle 'beneficiary pays' should apply to both the ODRC of existing assets and to new investments (assumed to be the optimum requirement at the best available price).

NECA has claimed that there was no demonstrable material benefit in applying 'beneficiary pays' principle to 'sunk costs'. As indicated in previous paragraph, as ODRC converts 'sunk cost' to long run marginal costs, such a change will facilitate efficient economic signals to beneficiaries of the network. There is also a negative **impact on competition in the upstream market** as well - in that existing generation currently gets a 'free ride' in that they do not pay for the transport of electricity to load centres but enjoy the economic benefit of locating close to supplies of raw materials. This places new embedded generation who locate close to load centres to reduce incidence of transmission charges, at a disadvantage to established generation in places like the La Trobe valley.

The resulting **impact on competition in downstream markets** would make electricity dearer than its substitutes (eg. gas) when compared to the situation if generators paid their fair share of transmission costs. This exemption of generator contribution to transmission costs also has a very significant impact on the cross subsidy position. By loading about half of distribution costs on the remaining part of the distribution network (eg Victoria), the cost allocation to remote rural customers become excessive. The political fall out of such misguided cost allocation is the cause of the 'postage stamp' type smearing of the excessive cost burden leading to a distortion of the economic signals. Further, in so far as the price cap is higher than what would have been the case if generators contributed to transmission costs, there would be greater incentive for ‘economic bypass’. If generators were to pay their fair share of transmission costs, this type of imposts on economically efficient pricing in downstream markets can be significantly reduced - maybe totally eliminated even.

To put the complexity of the proposal into perspective, say we look at transmission pricing in ten years time and even if there were even only 20 additional transmission investments since 1 July 2000, trying to keep track of when the particular network component was commissioned would be a nightmare. The **creation of two artificial classes of network assets** is not desirable and would have a negative impact on public benefit.

The NECA report fails to appreciate how price-setting practice deals with multiple objectives. The report argues that ‘sunk cost’ are not the correct basis to provide economic signals and so these costs should be collected in a manner that would create the least distortion in the markets. The report correctly recognises that equity is an equally important objective but fail to appreciate that **they apply to two stages of the price setting process**. The equity objective applies to the earlier step of apportioning costs and the objective of economic signalling apply to the rate design – the mechanism of collecting the apportioned costs. As a veteran electricity-pricing practitioner I fail to see the “fundamental clash of economic principles”. Even if one was to accept the argument that ‘sunk costs’ are not the correct basis for economic signals, the equity objective still needs to be satisfied. It is the equity objective that supports the ‘beneficiary should pay’ principle. In effect the NECA report put a higher emphasis on the ‘next best solution’ to the price-signalling objective (‘sunk costs’ are not the same as LRMC, therefore charge it to the customer at the end of the line..) at the expense of the all important equity objective – not a satisfactory outcome.

ACCC, having specific responsibility under the Trade Practices Act to safeguard public interest and to disallow provisions that have the purpose or effect (or likely effect) of substantially lessening competition in a market, should not accept NECA recommendation on the different treatment of ‘sunk cost’ and new investment. Sunk costs ‘transformed’ by the ODRC process should be treated the same as new investment and charged to generators as well, the cost apportionment being based on the ‘beneficiary pays’ principle.

b) need for price signals

NECA seems to be caught up in the frenzy of 'just in time pricing' and 'ultimate efficient outcomes' both designed to make the process very complicated and looking so disconnected from reality. In electricity pricing we have always placed a high value on keeping things simple so that prices are well understood (and accepted) and easily derived (no ambiguity). Businesses exist to make a profit and their shareholders would like the profits to be stable and predictable. Good market design should be concerned not only with delivering prices that are efficient, but stable, predictable and easily understood by market participants (and the public).

In looking at the trade offs between various objectives of setting prices, we need to be conscious of the significance of the different outcomes. Networks are considered natural monopolies, with long asset lives, very lumpy investments and considerable time required to add extra capacity. Signalling short run marginal costs for network investment does not make much sense.

Networks are important in that they facilitate competition in upstream and down stream markets. In the wholesale energy market (upstream) network losses and constraints impact on market price and on the dispatch of individual generators. As the wholesale market operates at the notional load centre of that region (in Victoria it is Thomastown), the losses and constraints that are of concern apply to that part of the network that enable the generators to deliver their output to the load centre in question (losses on the other parts of the network impact on the total demand but the significance on pool price is much less) and the inter-connectors that enable energy import to or export from the region. In the Victorian context we are referring to the 10 extra high voltage lines that link the La Trobe valley to metropolitan Melbourne and the extra high voltage lines that link the Victorian hydro stations to Melbourne. These lines constitute more than half of the Victorian transmission system (the generators currently pay almost nothing of the network capital cost or for their maintenance).

An indicative breakdown of the electricity dollar is given below, the figures being different for different DBs and for different States and depends on their customer load densities and generation energy sources:

Energy Generation	50 – 60 cents
Transmission	10 – 15 cents
Distribution	20 – 40 cents
Retail	8 – 12 cents

Average transmission costs are only around one fifth the average energy costs and minuscule compared to top end of the energy bid prices (even with VoLL at $ 5000 / MWh) that constitute the short run marginal cost of energy at times of system stress. Long run marginal cost of the network has significance in that it signals the cost of network augmentation and sets a value on network efficiency. Short run marginal cost for networks has no significance in that there is little response possible in the short term. Further the signal to be effective it has to be correctly targeted. If the short run marginal cost signal has no impact on the Network owner / manager, but has the effect of raising pool price paid by customers who bear no responsibility for the network, it would be a perverse signal doing only harm rather than any good. Any positively biased increase in pool price volatility is a transfer of funds from retailers to generators and should be avoided.

We need to keep in mind that the transmission network comes under an Access Regime subject to Regulatory supervision. It is left to the Regulator to devise performance standards and effective incentives to drive performance improvements. In so far as the Regulator emulates competitive markets, those who pay for the service should have a greater say on the matter – 'customer service'.

c) full nodal pricing

The axiom "horses for courses" is a good starting point in an assessment of appropriateness of full nodal pricing within NEM. NECA report draws heavily from practice in the New Zealand (NZ) market and the Pennsylvania New Jersey Maryland Interconnection (PJM). Unlike the NEM, which is a gross pool (all energy has to be sold through the pool), both NZ and PJM markets are balancing markets with large number of point-to-point bilateral contracts. As these markets also have central dispatch, to cost the delivery of these bilateral contracts it is necessary to determine the costs at various points in the system. NEM is a gross pool with settlement t notional regional load centres and do not need the complexity of full nodal pricing.

The ten primary PJM members (the bulk of the market) are vertically integrated utilities with generation, transmission, distribution and retiling. In effect PJM is akin to the 'Opportunity Interchange Agreement that existed between Victoria, New South Wales (and the contract with South Australia). PJM members make available their uncommitted generation capacity (and their arrangements for designated reserve requirements) **at cost** so that economic dispatch and security can be optimised. As generation capacity is made available to PJM at cost (marginal cost) it makes sense to use marginal costs of network services to optimise market operations. The networks are owned by member utilities and attract a predetermined and fixed $/MW payment, much like in the NEM. Transmission augmentation or new facilities, not within the current capital investment program, has to be paid for by the generator or load customer who requests that facility (deep connection costs as opposed to shallow connection costs that apply in the NEM).

The current system of region based nodal pricing we have in the NEM has worked well except for a few hiccups in Queensland and the legacy inter-connectors that were originally meant for other purposes. The shortcomings of the current definition of Regions is recognised and a review has already started. Re-alignment of Queensland and Snowy regions may be all that is needed to avoid the complexities of a full nodal market. It is hard to imagine how we can combine an energy only gross market, with full nodal pricing and also keep the five-minute dispatch as well. In the end something will have to drop by the wayside.

d) entrepreneurial inter-connectors and firm access

ACCC has done a good job in establishing the Access Regime for infrastructure assets and the entrepreneurial inter-connector with firm access seems contrary to the original reasons for the Access Regime. Problem of funding inter-connectors boils down to a methodology to fill the gap between public benefit and appropriatable commercial benefit. It is interesting to note that we now talk of hybrid entrepreneurial inter-connectors as a means of overcoming this problem.

Public benefit of such things as Universal Service Obligations, amenity value, global warming, etc can no longer be ignored. There are some other public costs that are not fully appreciated. Transmission lines get special treatment when it comes to accessing public and private land, easements, etc. The planning processes require that transmission schemes should have local community support. If the entrepreneurial inter-connector gets up first, it will appropriate these hidden public benefits but the second inter-connector (regulated, entrepreneurial or hybrid) over the same area might not be so lucky, eg fiasco of the cable TV roll-out. Should that first inter-connector then be subjected to an Access Regime?

ACCC draft Principles recognises the need for regulation to "replicate the outcomes of a competitive market". In previous decisions ACCC has laid stress on "effective competition or the real threat of competition", an outcome that may not eventuate once an entrepreneurial (or hybrid) inter-connector is commissioned.

e) Victorian Cross-Subsidies and the Universal Service Obligation (USO)

Cost of Supply studies done by the SECV in 1989, when prices were uniform across Victoria, indicated the locational cross subsidy from Urban users to Rural users was around $200 million a year. Except for the locational impact of energy losses (around $10 million) the bulk of the cross-subsidy was due to differences in network costs. The composition of the cross-subsidies was as follows:

SECV Cross-Subsidies For The Financial Year 1989/90

	Urban	Rural	Class Cross-subsidy
Domestic	-39.8	-149.3	-189.1
Business	247.7	3.5	251.2
Farm	-3.6	-54.6	-58.2
Other	3.9	-7.8	-3.9
Locational Cross-subsidy	+208.2	-208.5	0.0

Source: Pricing Development Plan (August 1989) - Discussion Paper No 1: Evaluation of Effects on Customers of Cross Subsidies and Potential Real Cost Reductions

These figures are only indicative as the model used in 1989 had some shortcomings. The reference to cross subsidies need to be qualified in that these figures (including the SECV table quoted in the ACCC Issues Paper) were derived in connection with rebalancing of tariffs and as such they include a return on capital (profits). In economic analysis cross subsidies are generally defined as cases where revenue is less than short run marginal cost and this was not the case at SECV. The 10% price increase for domestic customers in October 1992 and the ensuing industry restructuring has changed some of the costs and revenues. In spite of the shortcomings in the 1989 models and the restructuring changes of 1994, the locational cost difference (equalisation payment that would be necessary to maintain uniform prices) in servicing rural and urban customers in Victoria, is still likely to be in the $ 100 million to $200 million range, although no recent analyses are available. I expect the residual cross-subsidies are basically locational and will be shown in the class analysis reflecting the higher incidence of farm and residential customers in remote rural areas. As can be seen from the above table, the bulk of the cross-subsidy was from the Urban Business customers to the Rural Domestic and Farm customers. Unless this locational cross subsidy question is addressed in time, come January 2001 some Victorian rural customers are going to get significant price increases.

Locational cross-subsidies are justified on the basis of Universal Service Obligations (USO) that is recognised in Federal statutes such as for Telecommunications and the Postal Service:

The universal service obligation (USO) is the obligation:
"(a) to ensure that the standard telephone service is reasonably accessible to all people in Australia on an equitable basis, wherever they reside or carry on business; …" Telecommunications Act 1991 s288(1).

'(3) Australia Post shall make the letter service available at a single uniform rate for the carriage within Australia, by ordinary post, of letters that are standard postal articles.
(4) Australia Post shall ensure:
(a) that, in view of the social importance of the letter service, the service is reasonably accessible to all people in Australia on an equitable basis, .." The Postal Corporation Act - s27.

Until very recently responsibility for supply of electricity was vested in the States. Number of States had implicit USO schemes either by means of uniform tariffs across the State eg Victoria or modest variation in retail tariffs made possible by varying the rate of return requirement of the host retailer, as in New South Wales.

American economists such as Professor Paul Milgrom now recommend explicit subsidy funding rather than distorting the costs or prices in the industry. "The US Telecommunications Act of 1996 provides for the establishment of a fund to subsidise service to customers in high-cost-of service areas. The Act also requires that the subsidy levels in each area be adequate to cover the universal service provider's costs."

Addendum
As a good understanding of the processes that happened in the Victorian Electricity Industry Restructuring provides substantial insight into cross-subsidies, asset valuations, interim price paths, etc., a substantiative account of the main parameters in the restructuring process has been included in Appendix A. This account also sheds light to the origins of the 50% of TUOS being charged on a postage stamp basis.

As this submission is on a pro bono basis and the analysis contained in the Appendix A is to be published at a later date, appreciate if the contents of Appendix A are kept confidential at this stage.

Responses to Specific Issues Raised by the Commission Paper

This section of the Submission, provide responses to specific issues raised by the Commission Paper. As some of the key issues involved in the NECA Final Report need to be addressed in a particular manner, the earlier part of the submission went into more detail and developed the argument in certain sequence best suited to address those arguments. To enable the Commission to draw their conclusions from all the responses there is merit to provide a feedback to specific issues raised by the Commission in the sequence they have set.

4.1 Transmission network pricing

4.1.1 Existing arrangements

- Are the proposed Code changes sufficient to encourage networks to negotiate and provide generator access services?

- **Is there sufficient clarity to distinguish between the unregulated generator access services and the regulated generator negotiated use of system service (and any associated assets and revenues)?**

Regulated networks management generally do not have the expertise to deal with risk management products as originator. This should be the domain of the experts. Captive customers should not have to pick the tab if things go wrong. On the other hand, networks should be encouraged to engage in complementary activity that is within their traditional risk levels and certain portion of the benefits from them should flow back to the captive customers via the 'aggregate annual revenue requirement'. The proposed Code changes do not make this important clarification.

4.1.2 Who should pay transmission use of system charges

Existing network

- **Do interested parties believe that recovering the costs of the existing network from network customers minimises the distortions from recovering sunk costs?**

No.

Creating **two classes of network assets** creates problems for network owner / managers, customers and regulators. Setting a cut-off date is artificial and not defensible.
In the **upstream markets**, it only perpetuates current distortions, eg postage stamp methodology, inflates remote rural costs thereby exacerbating need for USO adjustments, provides artificial incentives for bypass by inflating remote area prices.
In the **downstream markets**, it provides cost advantage to established generators using long transmission lines to remain close to fuel sources compared to other generators located close to customer load centres.

- **Would the recovery of a proportion of the sunk costs from generators be less distortionary than the framework proposed in the NECA review?**

Yes.
It will substantially reduce the need for USO type adjustments, which was the reason for the postage stamp methodology. Points made above also apply.
NECA Report alludes such a change leading to higher charges to large customers with high load factor (and to small domestic customers?) but fail to grasp that when generators pay their fair share of Network Charges (true it will come back by way of increased c/kWh) there would be a corresponding reduction in the postage stamp component which is also on a c/kWh basis. The net result would be fairly neutral on that score.
NECA Report also maintain that generators are already subject to sufficient locational penalties due to price being impacted by losses and network constraints. All generators are in the same boat but some use the networks more extensively (at no cost) than others. The analogy would be to say that a car owner at a

remote location decides not to pay the road toll (assuming the benevolent Government has sold the road to the highest bidder) because he has to pay for the petrol to run his /her car or that he once missed his plane on such and such a day because of a traffic jam on the way to the airport..

- **Could the framework for recovering sunk network costs from customers also be applied to generators? That is, allocate a proportion of existing network costs to generators and allow individual, price sensitive generators, to negotiate discounts.**

Yes. Care needs to be taken in these type of situations to ensure there is a balance in the bargaining powers of different participants. Otherwise the generators with stronger bargaining power will get all the concessions and the end-use customers will continue to pay a higher charge than otherwise.

New investment

Issues for the Commission

- **Do interested parties believe that NECA's proposals introduce more "market like" disciplines into network's investment planning processes?**

Agree with the proposition that generators should pay their share of costs on a 'beneficiary pays' basis. Concerned about the 'devil is in the detail' style adopted. Section 1.3 is a very important section as it deals with Core Objectives and Key Principles. Hope it is not an ominous sign that Equity has been put as the last of the Core Objectives. Maybe as a result of the protracted deliberations, eg 'fundamental clash of economic principles', the 'beneficiary pays' principle has not been included in the proposed 3 Key Principles. That should be the supporting Key Principle that go with the Core Objective of Equity.

Implementation proposals are too complicated and not necessary if the network tariffs are properly designed.

- **Are NECA's proposals likely to be consistent with the future directions of network pricing in the NEM (such as nodal pricing and transmission congestion contracts which are the subject of a new review by NECA)?**

Proposals are too complicated and not necessary in a gross energy only market as we have in the NEM. More detailed discussion contained in earlier part of the submission.

- **Will regulatory responsibilities be fragmented if the code's dispute resolution procedures are used to arbitrate disputes between networks and connected users? If so, do interested parties believe the ACCC's regulatory powers should be extended to allow it to arbitrate such disputes?**

Yes. Code dispute resolution procedures have not proved to be effective in the case between the National Retailer Forum and NECCA. There is little hope then for satisfactory resolution of customer complaints. Further, great majority of customers are not Code Participants as defined in the Code. In the UK, the National Regulator performed this role admirably and I see no reason why ACCC cannot do the same.

4.1.2 How should transmission use of system charges be levied

- **Do interested parties believe that a move to long run marginal cost (or utilisation adjusted) pricing represents a significant improvement in transmission pricing?**

No. Not consistent with public benefit multiplier role of networks as facilitator of upstream and downstream competition. Benefits from both markets would be compromised if network pricing signals were ambiguous, unstable and erratic. Network owners / managers would also have hesitancy in committing substantial funding necessary for future networks if the level of uncertainty in their revenues were to substantially increase.

- **Do interested parties believe that the proposed pricing arrangements will ensure that network customers face charges that accurately reflect the needs for new investment at each connection point?**

No.

- **By using both short run (reflecting losses and constraints) and long run pricing methodologies, will there be over signalling of new investment at constrained parts of the network?**

Yes. The losses and constraints are the domain of the energy market as defined in the NEM and should not be doubled-up in network pricing as well.

- **Do the proposed Code changes provide sufficient guidance to require the networks to adopt efficient prices from within the cost ranges?**

No.

4.1.4 Summary of proposed changes to TUOS charges

a) Generator use of system service costs:

b) Customer use of system service costs

- **Do interested parties believe that the proposed Code changes reflect the findings of the NECA review?**

No.

4.2 Distribution network pricing

- **To what extent is a uniform approach to the development of principles for distribution network pricing desirable and should jurisdictional regulators develop, as a matter of some urgency, national guidelines for distribution network pricing?**

Yes, but not necessarily accepting all the recommendations in the NECA report.

- **Does the flexibility available to jurisdictional regulators in determining how distribution network service providers pass on TUOS charges to final customers weaken the applicability of the principles emerging from the NECA review?**

No. Jurisdictional regulators have in the past shown they are well attuned to specific circumstances of their respective State network systems and the ultimate interests of customers.

- **Other than NECA's proposals for a sizeable peak demand charge, what issues should be included in any review of distribution network pricing principles?**

Transmission network price structures should not be mandated in the Code. The network pricing methodology is well established and the owner / manager should have leeway to manage the process recognising the need for the final price structures and prices to be approved by the appropriate Regulator.

4.2

4.3 Price negotiation framework and unbundling transmission and distribution charges

- **Are the proposed Code principles and regulatory arrangements sufficient to guide the negotiation processes, in particular where one party (ie the network) is a monopolist and likely to have an information advantage over customers?**

- **Is it reasonable to allow some users to negotiate discounts but to require other users, presumably with less negotiating power, to bear the cost of the discounts?**

No.

- **Is it reasonable for negotiations on higher service standards to be subject to a network's negotiation framework yet negotiations on price discounts are not?**

No.

- **What sort of information should be publicly released on the outcome of the negotiations, in particular if the outcome is that some customers pay a greater share of someone else's network charges?**

  a) circumstances that make the case different from the general case.
  b) General impact of losing that customer
  c) What the concession will cost all the other customers

- **Is this negotiating framework sufficient to ensure that networks are limited in their ability to cross-subsidise some customers at the expense of others?**

No. There should be an in-built mechanism to discourage network owner / operators from being free with giving discounts, eg only a fixed proportion is recoverable or the recovery is staggered.

- **Should networks have the ability to negotiate lower service standards than those specified in the Code, in particular in lightly utilised parts of the network where providing N-1 may not provide a net public benefit but where investments proceed on the basis that they are "cost effective"?**

Some such flexibility is desirable but should be subject to customer acceptance.

- **Do the proposed Code changes meet customer expectations on the type and level of disaggregated information on network costs and prices?**

No.

- **Are the time frames reasonable in which requested information must be provided?**

- **Is it reasonable that the proposed Code changes have been inserted into a part of the Code which has been derogated by all of the participating jurisdictions and, therefore, will not come into effect in the immediate future?**

No.

4.4 Service standards

- **Do the proposed Code changes fully implement the findings of the NECA transmission and distribution pricing review?**

The NECA transmission and distribution pricing review extended over a very long time, but the opportunity to debate the final contents was not sufficient. The final contents are substantially different to contents which were debated in the early stages.

- **Do the Code changes impose sufficient obligations on the networks to establish clear and measurable service standards in advance of the determination of their revenue cap?**

No.

- **Has an appropriate balance been achieved between the responsibilities of the networks and independent parties (eg technical panels or regulators) in establishing network service standards?**

No.

- **Are the responsibilities and powers of regulators been clearly defined?**

No.

4.5 Embedded generation

- **In the absence of generators contributing to the costs of the existing (sunk) networks, does the proposed arrangements establish a competitively neutral environment for embedded generation?**

No. Refer to arguments why generators should pay for ‘sunk costs’.

- **Is it reasonable that the existing requirement has been deleted from Chapter 5 of the Code and replaced by proposed Code changes that are to be inserted into a part of the Code which has been derogated by all of the participating jurisdictions and, therefore, will not come into effect in the immediate future?**

No.

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

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

Other research & consultancy work cover:

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

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

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

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

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

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