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14 May 2007

Mr Mike Buckley
General Manager
Network Regulation North
Australian Energy Regulator
PO Box 1199
Dickson ACT 2602
By email: AERinquiry.PMG@aer.gov.au

Dear Mr. Buckley,

Transmission Pricing Methodology Guidelines

I welcome this opportunity to provide the AER with EnergyAustralia's (EA's) response to its Transmission Pricing Methodology Guidelines. There are a number of areas where we have concerns regarding the AER's pricing methodology, as follows:

- The pricing information requirements set out by the AER are not all appropriate for EA, whose pricing allocation is performed by a coordinating TNSP.
- Transmission charges are seen directly very few large customers and by DNSPs. Their structure must be capable of ready translation into prices which can influence customers' consumption patterns. There is no point in having sophisticated price structures that apply principally to DNSPs, if they cannot pass on those price signals to end use customers.
- None of the forms of locational demand charge proposed by the AER for transmission can be directly translated into customer's prices.
- Changes to the transmission cost allocation process can have potentially large price effects, particularly for larger customers. However, the current 2% side constraint on movement in the locational price component is quite incompatible with the use of pricing to manage demand.
- The original intent of the transmission cost allocation was that the locational component should pass on the Long Run Marginal Cost of network investment to meet demand. The postage stamp allocation of other charges was intended to recover sufficient revenue, whilst not distorting customers' consumption decisions. The process used for the postage stamp allocation can potentially have a greater price impact than the locational component and is not subject to the 2% side constraint.
- The AER's disclosure regime must recognise that the prices and connection arrangements of large customers must remain confidential to the businesses concerned.

If you have any queries regarding this submission please do not hesitate to contact me on (02) 4951 9411or Mr. Harry Colebourn on (02) 9269 4171.

Yours sincerely,

Geoff Lilliss
Executive General Manager – Network

EnergyAustralia™

Transmission Pricing Methodology

AER Issues Paper

May 2007

Contents

1 Introduction

EnergyAustralia is pleased to have the opportunity to comment on the AER's draft Transmission Pricing Methodology. EnergyAustralia (EA) is uniquely placed to comment on these issues, as we own and operate an integrated network business having both transmission and distribution functions.

EA is required, as are other TNSPs, to set transmission prices for the transmission component of its network. There are several large customers connected to that network, to which these transmission prices apply directly. EA also passes on transmission charges to the Retailers who supply its 1.5 million customers, as a component of their Network Use of System (NUoS) charge.

In the decade since market start, EA has been refining the cost reflectivity of its distribution network pricing and it leads the industry in rolling out Time of Use (ToU) pricing to both business and domestic customers. We have well developed views and soundly based analysis of how cost reflective network pricing should operate and on the efficacy of pricing structures in influencing customer demand. Our flat and inclining block tariffs for smaller customers have been obsolete since April 1995, and ToU has become our basic tariff. ToU is applied to all new and upgraded customer connections as well as being rolled out to customers with an annual consumption of 15 MWh or more. EA is the first utility in the world to have taken this far reaching step.

In this report, we provide an overview of the means by which EA develops cost reflective distribution tariffs for end use customers. This is necessary to place the transmission pricing arrangements in context, since demand management through tariffs will only arise from end use customer actions and preferences. We go on to comment on aspects of the AER's pricing methodology and finally respond directly to the questions posed in the AER's report. To summarise, the principal areas where we have concerns regarding the AER's pricing methodology are as follows:

- The comprehensive pricing information requirements set out by the AER are not all appropriate in the context of a TNSP like EA, whose pricing allocation is performed by a coordinating TNSP.
- Transmission charges are seen directly by only a handful of very large customers (like aluminium smelters and heavy industry) and by DNSPs. Their structure must be capable of ready translation into prices which can influence customer consumption patterns. Furthermore, that structure is constrained by the available metering. There is no point in having sophisticated price structures that apply principally to DNSPs, if they are unable to directly pass on those price signals to end use customers.
- The small proportion of large end use customers that have demand and capacity charges are billed monthly for their half hourly peak kVA or kW demand occurring during peak and shoulder periods in the prior month. Smaller customers increasingly have ToU energy based charges and with the imminent introduction of Advanced Metering Infrastructure (AMI) this should become the basic tariff for all small customers. None of the forms of locational demand charge proposed by the AER for transmission can be directly translated into customer's prices.
- Changes to the transmission cost allocation process can have potentially large price effects, particularly on large end use customers. This may well be appropriate, if the allocation passes on the marginal cost of augmenting the network. However, the current 2% side constraint on movement in the locational price component is quite incompatible with the use of pricing to manage demand.

- The original intent of the transmission cost allocation was that the locational component should pass on the Long Run Marginal Cost (LRMC) of network investment to meet demand. The postage stamp recovery of other charges was intended to recover additional revenue (in the manner of a two part tariff) whilst not distorting customers' consumption decisions. The process used for the postage stamp allocation can potentially have a greater end use customer impact than the locational component, as a greater proportion of costs are allocated in this way. Furthermore, it is not subject to the abovementioned 2% side constraint.
- The AER's disclosure regime must recognise that the prices and connection arrangements of large customers must remain confidential to the businesses concerned.

2 Overview

The Chapter 6A transmission pricing rule changes were developed by the AEMC and came into effect on 28 December 2006. The AER is required to develop a Transmission Pricing Methodology Guideline, in accordance with the principles set out in Part J of that Chapter.

As the first step towards the development of this Transmission Pricing Methodology, the AER has developed an issues paper and is seeking responses from stakeholders. Draft Guidelines will have a second round of consultation and the final Guidelines are to be published on 31 October 2007.

2.1 Existing transmission pricing arrangements

TransGrid acts as the coordinating TNSP under the Rules and calculates the transmission cost allocation for NSW TNSPs (TransGrid, EA, Country Energy and Directlink) from data provided by each party. The cost allocation process used is the standard CRNP, which was developed for and has been used since the start of the Market in December 1998.

There is currently freedom selecting the structure of the locational TUoS component - each TNSP can determine this to suit its circumstances. TNSPs have adopted a variety of structures: TransGrid has a variable component which comprises a $/kW demand charge plus a ¢/kWh rate on peak and shoulder energy, as noted in the AER’s discussion paper.

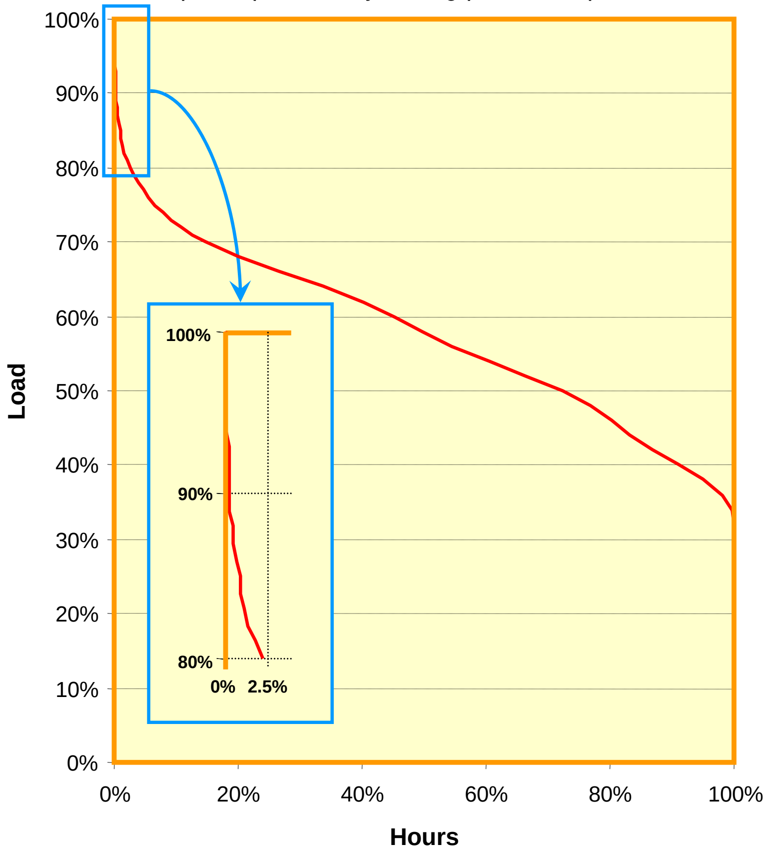
It is also important to note that EA passes on its TUoS charges to many of its end use customers through a peak and shoulder ToU energy rate. The rationale behind this choice of transmission price structure, which remains valid, was that it could be directly included in the prices of the greatest proportion of customers (ie. those with ToU).

At one transmission connection point, namely Bunnerong, the high load factor of large industrial customers has led to the adoption of a capacity based allocation of TUoS general and common service costs, as permitted under the Rules. Three large energy intensive customers at that location enjoy a capacity based transmission cost allocation and capacity based price structure.

Altogether, EA has six direct customer connections to the transmission network and around 50 large customers for whom the transmission price represents a significant component of their network charge. The RAC network has multiple connection points to EA’s transmission and distribution systems.

3 Cost reflective network tariffs

For many years, EA has advocated cost reflective network tariffs, in order to provide price signals which will encourage customers to reduce consumption, particularly during peak load periods. In this way, the high cost of providing network capacity for peak loading periods is mitigated.



The incidence of system loading is illustrated by the load duration curve for the whole of EA's network at right, where it may be seen that at periods of high load, the network is used for a small proportion of hours[1].

Network reinforcement in individual locations must meet specific local conditions; however these generally fall within the top 70-80% of the system load duration curve. This cost incidence is used to construct cost reflective network tariffs which apply to the whole of EA's network. In particular, the cost incidence drives the relativity between the components of the ToU prices discussed below.

3.1 Relationship of network prices to Long Run Marginal Costs

In the context of a business where system asset lives are 40 years or more, it is necessary for forward investment costs to be reflected in prices. To mitigate consumption, it is desirable that the Long Run Marginal Costs (LRMC) of the network business be incorporated in prices. Only in this way can appropriate price signals be provided to influence customers' consumption behaviour and their long run choices of equipment and appliances.

The LRMC of network expansion has been calculated as:

$$\text{LRMC} = \frac{\text{NPV(growth related capital expenditure)}}{\text{NPV(increment in load supplied)}}$$

This has a value which averages around 80% of the average price, for the great majority of customers connected to the Low Voltage (415/240V) network.

1 This illustration is for the years FY99 to FY06, with normalised annual energy consumption. Loads in summer have been scaled up by 5% and loads in winter scaled down by 5%, to take into account the effect of ambient temperatures on network equipment ratings.

Where practicable, this cost structure is translated into multi-part tariffs with consumption related component(s) of around 80% and a fixed charge of around 20%[2].

3.2 Customer metering arrangements

The most important limitation to the cost reflectivity of network prices is the type of metering installed. Meter requirements are specified in the Rules and Metrology procedures. Some of the feasible options are summarised in the illustration below.

	kVA demand ToU	kW demand ToU	Seasonal energy	ToU energy	single rate energy
Type 3 meter (>735 MWh p.a.)	✓	✓	✓	✓	✓
Type 4 meter (>160 MWh p.a.)	X	✓	✓	✓	✓
Type 5 meter (MRIM)	X	?	✓	✓	✓
Type 6 older ToU energy meter	X	X	X	✓	✓
Type 6 single rate energy meter	X	X	X	X	✓
Improved pricing cost reflectivity					

In broad terms, the tariffs which may be applied with Type 6 meters are limited to the least cost reflective forms. The emergence of Type 5 manually read interval meters (which have become the standard replacement meter for many DNSPs) has permitted the more widespread introduction of ToU prices. EA's position in this regard is set out below.

Whilst kW capacity and demand charges are also available Type 5 metering, the cost of monthly manual reading, required to permit monthly customer bills, limits its applicability.

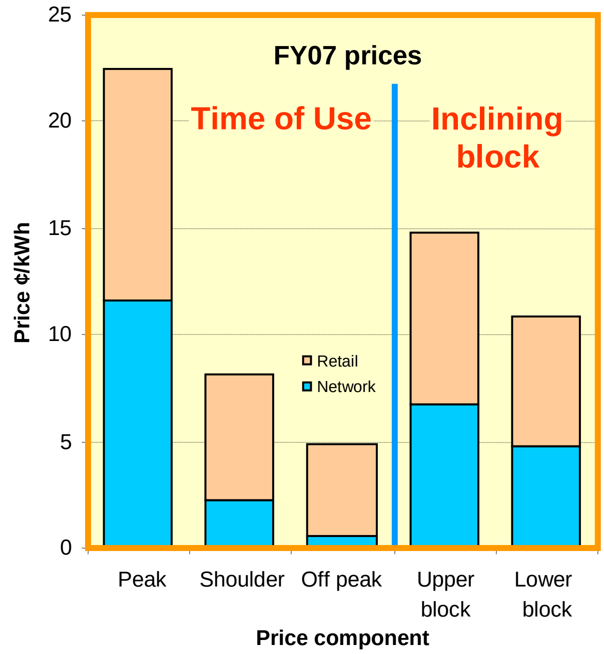
Types 3 and 4 meters are remotely read and offer the greatest range of possibilities in terms of pricing, although only Type 3 meters for the largest customers permit the use of kVA charges for capacity or demand.

The meters currently under consideration for Advanced metering infrastructure (AMI) for small customers would permit all of capabilities of Type 4 meters and, with additional communications permit the use of dynamic peak pricing.

2 Metering and other limitations constrain the application of this ideal price structure. Where a fixed component cannot be employed, anytime energy provides the least distortionary alternative.

3.3 Time of Use tariffs

In line with this drive to improve the cost reflectivity of network tariffs, EA has been implementing significantly more cost reflective Time of Use (ToU) tariffs during the current determination. EA now has over 100,000 customers on ToU prices, and by the start of the next determination expects between 300,000 and 400,000 customers (of a total of 1.5 million). ToU is applied to all new and upgraded connections to the network and is being rolled out to customers with annual consumption of more than 15 MWh.



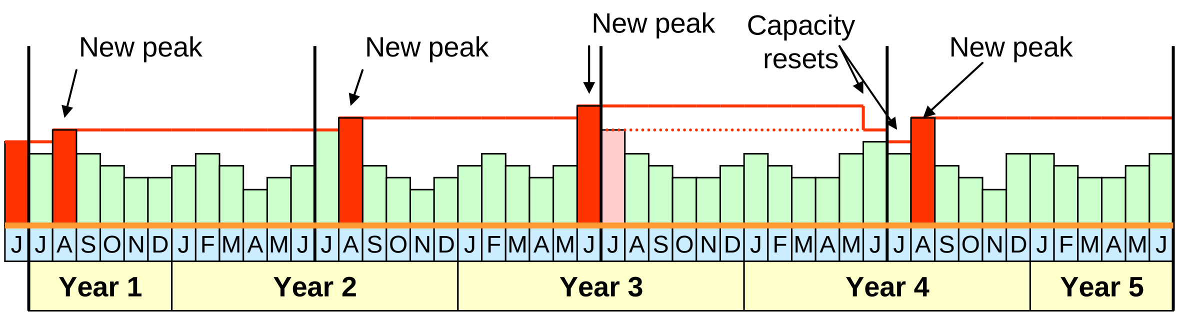
EA's ToU price structure for domestic customers is illustrated at right. It has a very significant differential between peak and off peak network charges, to encourage customers to shift consumption away from peak periods.

This differential between the ToU network components has been increased to broadly align with the cost reflective level for the network.

The differential between the upper and lower Inclining Block rates has also been progressively increased in the last few years and is proposed to increase by a further 10% in FY08.

3.4 Demand and capacity based tariffs

For larger business customers, EA commonly uses monthly demand and annual capacity charges, in addition to ToU energy rates. Demand and capacity charges apply to the peak kW or kVA consumed during a month. In the case of the capacity charge, the charge is reset on a rolling 12 monthly basis, as illustrated in the following diagram.



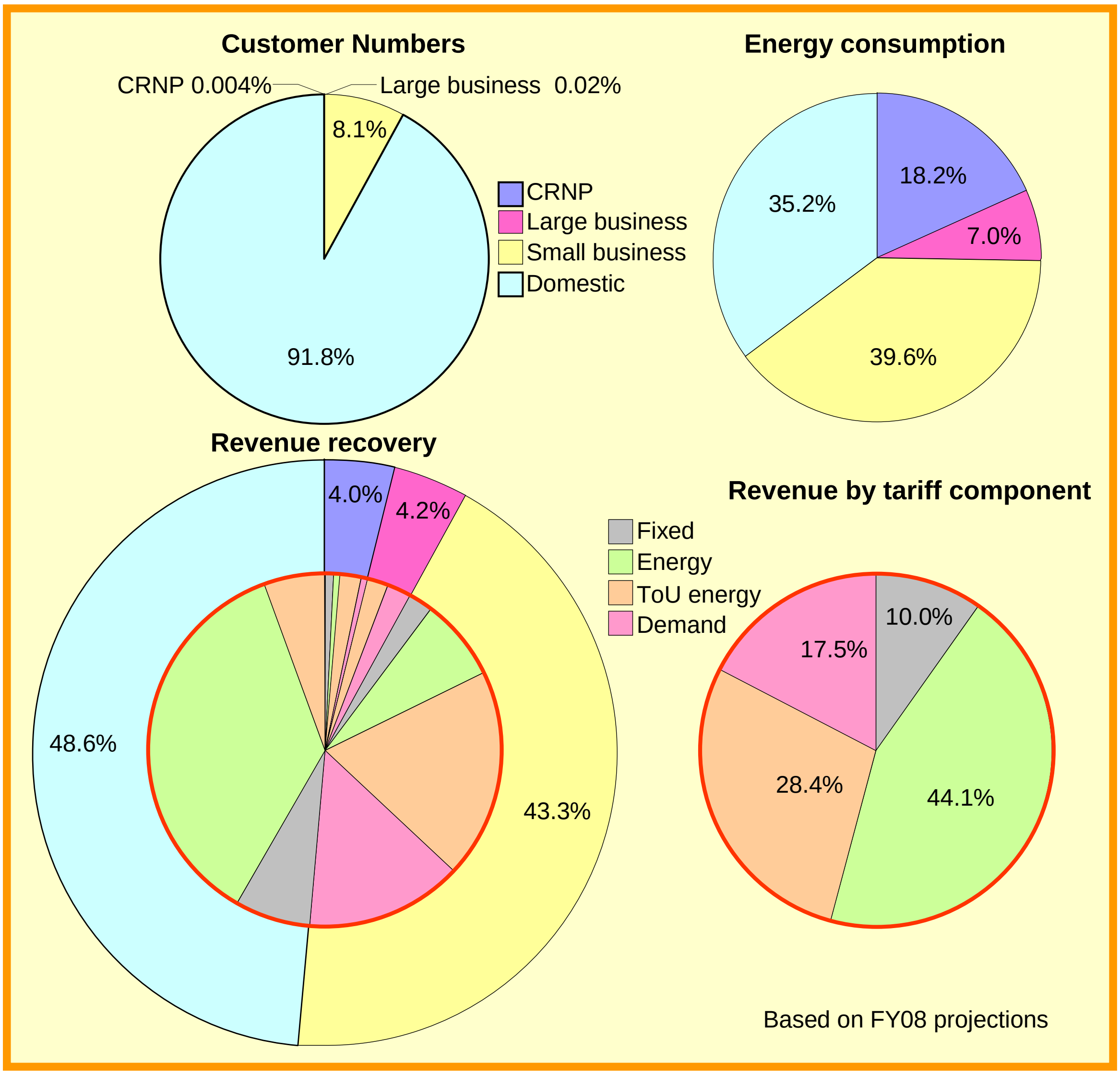
The advantage of the capacity charge is that, being based on the highest demand in the prior 12 months; it picks up seasonal variations in demand and therefore the peak summer and winter load periods. Moreover, as the capacity charge is based on metered quantities, it avoids the subjectivity associated with assessed demand charges whilst providing a similar charge regime with certainty concerning the reset and incentive.

Where a customer can demonstrate a sustained reduction in demand, for example through the installation of power factor equipment, a reset of the capacity charge is permitted.

EA is transitioning all demand customers to a capacity charge over the next two years

3.5 Customer characteristics

In order to understand what can be done in terms of customers' reaction to pricing signals, it is important to understand the characteristics of customers connected to the distribution network. The following diagram illustrates this.



The upper left pie chart shows the customer numbers of the various types of customer. The great majority of customers are domestic (92%), with a smaller number (8%) of small businesses. There are very small numbers of large businesses (High Voltage connected) and large customers with individually calculated (Cost Reflective Network Price or CRNP) prices.

The energy consumption by these classes of customer (upper right) differs markedly, with only 35% of total energy consumed by domestic customers.

The average network price of customers also varies, with the significantly higher costs of distribution to the Low Voltage level dominating. Hence 95% of the revenue is recovered from smaller customers in the outer pie chart on lower left.

The inner pie chart on lower left shows the proportion of revenue collected by each tariff component. These are aggregated in the chart on lower right. EnergyAustralia differs from other DNSPs in that a much greater proportion of revenue is recovered through ToU tariffs and this proportion is increasing with the progressive roll out of this form of price.

As mentioned in Section 3.4, monthly demand charges are being phased out in favour of capacity related charges.

The bottom line to this section is that ToU energy and demand/capacity charges are capable of influencing customer's demand response. However at the current time these apply only to 46% of revenue raised through prices. Nevertheless it is important to recognise that these forms of pricing are the only way in which transmission demand signalling is conveyed to customers and can influence customers' peak period consumption.

3.6 Customer response to Time of Use tariffs

At the retail price level, which is what ultimately influences customer behaviour, there are still significant incentives to reduce consumption in peak periods despite muting of the network signals by the retail component.

Customers may be expected to progressively transfer consumption away from peak periods, as familiarity with the product develops and as their appliance stock changes. Preliminary results of the customer elasticity of demand for ToU customers (obtained by comparison with a control group of customers) confirm this trend[3].

		Peak Own Price Elasticity	Peak to Shoulder Cross Price Elasticity	Peak to Off Peak Cross Price Elasticity
Domestic	**Summer 2006**	-0.30 to -0.38	-0.07	-0.04
	Winter 2006	-0.47	-0.12	(not available)
Business (less than 40MWh pa)	**Summer 2006**	-0.16 to -0.18 (not statistically robust)	-0.03	(not available)
	Winter 2006	-0.20 (not statistically robust)	(not available)	(not available)
Business (40 to 160 MWh pa)	**Summer 2006**	-0.03 to -0.13 (not statistically robust)	(not available)	(not available)
	Winter 2006	-0.02 to -0.09 (not statistically robust)	(not available)	(not available)

The table above highlights an elasticity of demand similar to the long run average for NSW calculated by NIEIR and used by NEMMCO in their statement of opportunities. This was used to justify the roll out of ToU to customers above 15 MWh.

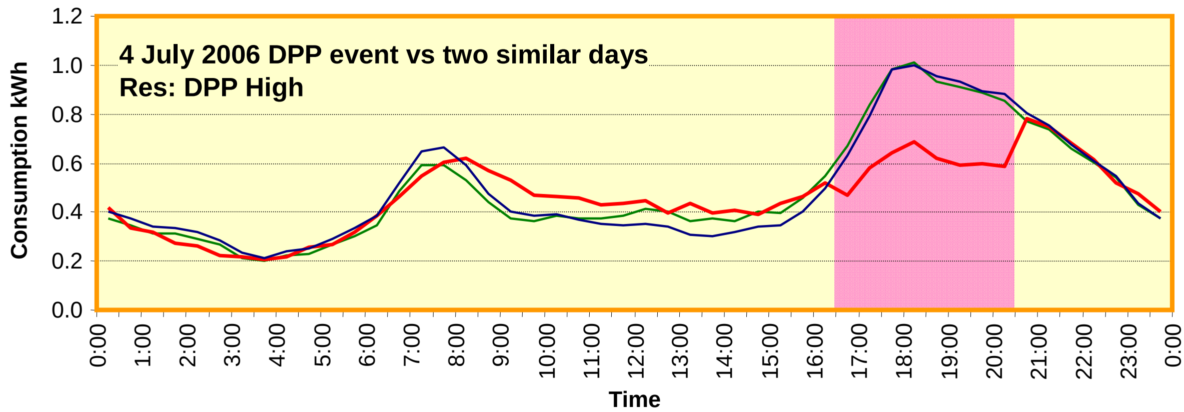
3 Alex Miller "EnergyAustralia's Critical Peak Pricing Trial: Sample Design, Customer Acquisition and Initial Demand Response", 30th International Conference for the International Association for Energy Economics, Wellington, New Zealand, 18-21 February 2007.

The larger diversity of the business customer base has led to results which, whilst still consistent with the average trend, are not as significant as for domestic customers. Further analysis of these outcomes will be carried out.

3.7 The future - dynamic peak pricing

EA's Strategic Pricing Study involves a sample of 1,300 customers and is mainly designed to trial the use and customer acceptability of congestion or dynamic peak based pricing. It is likely to be the forerunner of a range of such products which rely upon the use of AMI.

The SPS pilot has been set up to allow 12 dynamic peak price (DPP) events to be called each year. The DPP events have a very strong price signal, at $1/kWh or $2/kWh. An example of a DPP event on 4 July 2006 is shown.



The pink shaded area represents the period of the DPP event and illustrates the significant reduction in consumption that may be obtained from this form of pricing, compared with similar days when the price signal was not present. Summer 2006/07, however, had relatively few hot days and high generator price events. As a result, only 4 of the 6 possible events available under the customer contract were called. The statistical analysis of these events is currently underway.

EnergyAustralia is also conducting a parallel AMI pilot program. The purpose of this program, which will involve 10,000 customers, is to investigate:

- The alternative metering and communication technologies available;
- Installation costs; and
- Operational benefits.

The intent of this research is to inform EA's business case for the introduction of AMI.

4 Specific issues

The following section provides responses to the specific issues raised by the AER.

4.1 Information requirements

Q1. What additional information should be sought by the AER to assist it in determining whether a *TNSP*'s proposed *pricing methodology* is consistent with the *Pricing Principles for Prescribed Transmission Services* and Part J of Chapter 6A of the NER?

Q2. Is any of the information contained in section 6.1 unnecessary to determine whether a *TNSP*'s proposed *pricing methodology* is consistent with the *Pricing Principles for Prescribed Transmission Services* and Part J of Chapter 6A of the NER?

The AER has set out in detail in its discussion document the information required to monitor compliance with the proposed Pricing Methodology Guidelines. However, there has been no consideration given to the situation where the transmission prices in a jurisdiction are calculated by a lead TNSP for the other networks in the jurisdiction. This is the situation in NSW, where TransGrid calculates the transmission prices from information provided by the other TNSPs (EA, Country Energy and the Directlink Joint Venture). A common approach and pricing allocation is used for the pricing calculation and each TNSP may then determine its price structures from the allocated cost at each transmission connection point.

It would be unnecessary for each TNSP to provide full details of the pricing allocation and therefore an abridged set of information germane to the circumstances of each TNSP would be more appropriate.

4.2 Locational pricing structures

The AER has canvassed several demand based pricing structures for the locational portion of the TUoS charge. This is the portion of the TUoS charge intended to influence customer consumption patterns which in an ideal world would represent the Long Run Marginal Cost of expanding the transmission network at the connection point concerned.

The AER appears to have assumed that the AEMC intended to allow demand based pricing structures only (and that therefore energy based prices and fixed prices would not be permitted). The relevant Rule is 6A.23.4(e), which states: "Prices for recovering the locational component of providing prescribed TUoS services must be based on demand at times of greatest utilisation of the transmission network and for which network investment is most likely to be contemplated". Arguably this is broad enough to accommodate usage based pricing at times of peak demand, which single instance has a probability of occurrence within peak utilisation periods.

Moreover, the AER's pricing methodology guidelines should not attempt to exhaustively state permitted pricing structures for the recovery of the locational component of TUoS (or any other pricing structures). The Rules require the pricing methodology guidelines to "specify or clarify ... permitted pricing structures ..." (clause 6A.25.2). The guidelines should not therefore narrow the scope of the Rule. Instead, while the AER may through guidelines specify some pricing structures that the AER considers would meet the test in the Rule, it should remain open for other pricing structures to be submitted which also meet the Rule test.

In this context, it was pointed out in Section 3.4 that the structure of customer demand/capacity charges for the relatively small number of large customers that have them is a kW or kVA charge with a monthly reset, applied during peak periods only.

The following table sets out a brief summary of each option.

Option	Description	Comment
1	Maximum half-hourly demand at each connection point in each weekly billing period.	Weekly bill period does not line up with customer bill cycle Charges do not correspond with network summer and winter peak periods, which generally drive capex.
2	As above but limited to demand occurring in "peak" loading periods.	Weekly bill period does not line up with customer bill cycle Charges still do not correspond with network summer and winter peak periods, which generally drive capex.
3	Another pricing structure option would be to measure demand across the *billing period,* but to select only the maximum half-hour demand recorded for each *connection point* in that period. This value would be applied to the pre-determined price to arrive at a charge. This option would capture the maximum demand for the *billing period* and would result in levying charges based on times of high utilisation of the transmission network in that *billing period*.	Unclear how this differs from option 1 Weekly bill period does not line up with customer bill cycle Charges still do not correspond with network summer and winter peak periods, which generally drive capex.
4	Average daily maximum demand over a number of days (say 10) during a specified peak period, which drives transmission network investment.	Customer charge is driven by its consumption and its ability to foresee peak periods. Very significant issue over which days count towards the demand charge – decided retrospectively (like the British triad) or nominated in advance?
5	Agreed or contract maximum demand at a connection point at times of peak utilisation.	There is a level of discretion in the assignment of contract demand. Charge in effect becomes fixed which limits its effectiveness in signalling reduces peak consumption. Capacity charge as used by EA uses actual metered demand and is preferred.
6	Demand charge based on the actual carrying capacity of the network at a connection point – ie. lower if spare capacity exists.	Modified CRNP achieves this objective by scaling the 50% locational component to account for network utilisation. Estimating the utilisation of elements servicing a connection point is not a trivial exercise in a meshed network.

Q3. Given the requirement to signal efficient investment and utilisation decisions, which of the pricing structure options discussed would be most appropriate for the recovery of the locational component of *prescribed TUOS services*?

The six options discussed blur the two independent concepts of ***cost allocation*** and ***price structure***. The first five focus on the price structure (presumably with a common cost allocation approach) whereas the last varies the cost allocation, without considering the price structure.

Of the demand structure options discussed, *Options 1 to 3* do not provide a charge which signals the utilisation near times of peak network usage and should not be considered. Furthermore, the focus on a 7 day period is out of step with both TNSP and customer billing arrangements.

Option 4 is similar in concept to the British National Grid's "Triad" method of charging for maximum demand. This is used to recover the majority of transmission charges (ie. not just a locational component) and has spawned a support industry in Triad prediction and Triad dodging. Participants commonly engage in demand reduction on predicted peak days, which can have the effect of altering the Triad days.

The use of a greater number of demand instances (eg. 10) and a smaller utilisation charge would reduce the likelihood of participants engaging in inefficient avoidance activities. Nevertheless, such a system is not recommended. By nominating the applicable peak period after the event, the customer's demand charge is in effect scaled to their contribution at the peak time. It would also add a very great deal of complexity to billing arrangements if it were intended to pass such a charge on to customers. Notification in advance of peak periods (through a ToU or seasonal ToU structure) is strongly preferred as customers can more efficiently plan and invest to avoid consumption during peak periods.

Option 5 does not have the potential to provide an appropriate price signal as the assessed demand charge in effect becomes fixed. It therefore does not provide an incentive other than to restrict consumption to below the assessed "cap". (Assuming that the demand charge would be reassessed annually).

Option 6 involves a different cost allocation approach, rather than charge structure. In principle, this should provide charges that more appropriately represent the LRMC of network investment. This approach would be provided by use of the modified CRNP approach and this development is supported in principle by EA. However, it should be noted that there are some significant hurdles to its adoption, including establishing a sensible and repeatable capacity scaling approach for the elements of a complex meshed network where reinforcement is based on (n-1) and (n-2) considerations.

Within NSW, TransGrid intends to investigate this alternative with the assistance of the other TNSPs. A caveat to altering the form of cost allocation is that this would alter (potentially significantly) the allocation to large end user customers to whom transmission represents a material cost. Significant work remains to be completed before the potential impact of such a change can be assessed and its application reviewed.

In summary, <u>none</u> of the five pricing ***structure*** options discussed provides a charge which is both reflective of the cost of consumption during periods of peak network utilisation and able to be readily translated to end use customer prices.

Q4. To what extent would the pricing structure options discussed deter efficient investment and utilisation decisions?

Efficient investment and utilisation decisions will be made by both networks and customers if the network charges passed on to customers represent the marginal cost of delivery to them. In the context of networks, the short run marginal cost is effectively zero (as losses are transacted in the energy market) and so it is long run costs associated with future network investment that must be preserved in prices.

From the perspective of transmission networks, it is the cost of investment to maintain supply to transmission connection points that must be passed on through prices at those connection points. The connection points are largely to distributors and generators, and a few very large energy intensive customers.

There is no point in having complex price structures at transmission connection points. DNSPs are unable to act on such price structures. Moreover, the boundary of the transmission network is not fixed, as it depends upon the connection configuration of the network. Rather, it is the consumption of end use customers that that must be influenced to mitigate peak demand and the transmission price structure must be of a form that can be readily incorporated into customer prices.

Q5. How could the pricing structure options canvassed be modified to better reflect the requirements of the NER.

Whilst having some commonality with Option 5, EA's current capacity charge is a much more effective method of charging for demand imposed on the system. The charge is based on the highest kVA or kW consumption in peak periods occurring during the previous 12 months. Thus for loads having a seasonal component, the demand on the network in the peak season provides the basis of the charge for the following 12 months. In addition, this approach removes any subjectivity in the charge assessment, by relying on metered quantities.

The five locational pricing structure options discussed all fail the basic requirement of being able to readily translated into customer prices. What is required is:

- A demand or capacity structure similar to that currently used by DNSPs, with a ToU or seasonal component and monthly billing. This could then be directly passed through to the charges of large customers; or
- A ToU or seasonal ToU energy rate. This would have the advantage of being readily included in the charges of a far greater proportion of customers, including domestic customers.

Q6. Can a price based on demand at times of greatest utilisation of the transmission network include an *energy based price* or a fixed price?

In EA's view a ToU or seasonal ToU energy price offers the most attractive structural option, from the viewpoint of being able to be directly incorporated into the greatest number of customer prices. This transmission price structure complements the distribution price and is passed through as a bundled network charge. The differential in price between peak and off peak components can be substantial, to truly reflect the LRMC of consumption during peak periods.

Furthermore the ToU price structure, being relatively simple, is capable of being billed by a large proportion of both DNSPs and Retailers. It is also conveyed as a relatively simple message to end use customers.

Q7. Are there any implementation issues which might impede the use of the pricing structure options canvassed?

The most significant implementation issue with transmission pricing lies beyond the transmission networks. TNSPs have a very small number of customers and can readily bill complex price structures to DNSPs, generators and the few energy intensive customers.

The transmission price structures need to be reflected in end use customer charges and the efficacy with which this can be carried out represents a significant implementation issue, as outlined in the response to Question 3. The least common denominator in this equation is the Distribution Network and Retail billing systems for end use customers.

All DNSPs currently bill demand and capacity based charges for their larger customers. They also have the ability to bill ToU charges. Retailers differ in their capability and specialisation but increasingly are capable of billing ToU to smaller customers.

Q8. If the *demand based pricing* structure options are not appropriate, or are impractical, what *demand based pricing* structures could be implemented?

As noted in the response to Question 5, the capacity charge is a variant of the kVA or kW demand charge which offers significant advantages in signalling capacity related costs to larger network users.

Q9. To what extent is consistency across the NEM required when specifying a *demand based pricing* structure for this component of *prescribed TUOS services*? To what extent are the various options compatible with each other?

EA does not consider that consistency across the NEM is required with demand based charges. The need to reinforce the network can arise from various conditions – due to summer or winter loading and possibly in between, depending upon seasonal generation and interconnector flow patterns. There therefore needs to be some flexibility in permitting TNSPs to set price structures that reflect the cost drivers for their networks.

What TNSPs do need to be conscious of, however, is the requirement for these price structures to be translated to end use customer prices.

Q10. Would additional costs be incurred by TNSPs in adopting any of the *demand based pricing* options discussed, and if so, can these costs be quantified?

The use of kVA demand or capacity charges (rather than kW) at some transmission connection points would result in additional metering costs, which should be readily quantifiable.

Unlike DNSPs and Retailers, the TNSP's billing systems do not have to accommodate large numbers of customers and thus their modification is not likely to impose great cost. It should be noted that a requirement imposed on DNSPs and Retailers to directly pass on demand based transmission charges could potentially be very costly, unless the demand based charge were specifically constructed to mirror current pricing structures.

Q11. What is the likely impact of the *demand based pricing* structure options canvassed on all classes of network users?

For the purpose of responding to this question, the following classes of network users have been separately considered:

- *Generators*: do not currently bear TUoS locational charges and would not be affected. However, the imposition of a TUoS charge on generators is a matter which EA continues to support for many reasons. If such a locational charge were to be imposed, a capacity based structure would most appropriately recognise the capacity provided by the transmission network to convey energy from generators to major load centres.

- *DNSPs:* pass through transmission charges to Retailers and directly to some very large customers. Their principal interest is in having a demand or energy based transmission pricing structure that can be combined with the distribution charge into a bundled network price which is capable of influencing customers' consumption patterns.

- *Retailers:* pass through network and market related charges to end use customers. Their principal interest is in having price structures which can be billed and explained simply to the greatest variety of customers.

- *Transmission connected large customers:* in EA's case, the transmission charges are passed on directly to the customer concerned. One exception to this is the Rail Access Corporation (RAC) below. These customers require a transmission price structure which matches the traditional ToU energy and demand/capacity arrangements.

- *Distribution connected large customers:* As for transmission connected customers, these customers require a transmission demand or energy based price in the traditional form. These customers receive a bundled rate and upon request a breakdown of the price components is provided. Thus consistency of the transmission price structure with current distribution price structures is important.

- *ToU energy customers:* An increasing proportion of EA's customers are falling into this category with roll out of interval meters and availability of the ToU price. With the eventual introduction of Advanced Metering Infrastructure (AMI = interval meters with communications) there is little doubt ToU will become the basic price for all customers. For these customers, a ToU based price to reflect the locational component of transmission cost is desirable.

- *Flat energy customers:* Until the introduction of AMI there is little that can be done with this large block of customers to reflect their transmission demand related charge. It simply forms a component of their energy based charge.

Some practical implementation issues would arise if demand based charges were required to be passed on to transmission connected customers, without some discretion by the TNSP or DNSP as to the form of the charge:

- The Rail Access Corporation (RAC) network has several points of connection to the EA and Integral networks in the Sydney area and in EA's case also has a number of direct connections to the transmission network. The RAC network is capable of through flows (in the manner of a transmission network) as well as supplying connected loads. A decade ago, the disparate RAC prices were merged to a single ToU energy structure, to resolve issues of over charging for the demand at individual connection points where through flow was superimposed on loads. A requirement to pass on a demand based charge at the transmission points of connection would reintroduce the problems of the past.

- The price structures of large customers in most, but not all cases, have a capacity or demand charge. Where they do not, a very significant alteration to the current price would result.

Q12. What is the benefit of consistency in pricing structure to network users in general, and to specific types of users in particular?

Benefit of general consistency to consumers including simplicity and understandability. In this regard simple ToU structures are recommended – accepted and understood.

The main benefit of consistency in network price structures is to Retailers. Each Retailer must be able to bill all of the network tariffs for their customers.

Q13. To what extent do the current pricing structure arrangements provide signals for efficient network investment and utilisation decisions?

EA's initial demand elasticity results for ToU are discussed in Section 3.6; this work is the subject of ongoing research but clearly indicates the potential for relatively simple price structures to influence customers' peak period consumption. It is anticipated that the longer term response, as customers become more familiar with the product, and their investment decisions are influenced, will increase

It is the bundled (transmission + distribution + retail) charge which will influence customer decisionmaking and the transmission demand component cannot be considered in isolation.

Q14. What implications arise in considering whether *demand based prices* might be better expressed in dollars per kVA per time period, as opposed to dollars per kW per time period?

The power factor permissible for automatic access standard at both transmission and distribution network connection points is set out in the Rules (Schedule S5.3.5). There would therefore seem to be little justification for pricing to reflect the power factor at the connections of distributors to the transmission network.

Notwithstanding the Rules requirements, it is generally more economical in terms of capital cost for power factor correction to be carried out at higher voltage levels. This capital cost must be balanced against the need to size the upstream network to carry the total active and reactive load.

There is therefore logic in maintaining KVA demand and capacity charges for larger customers in order to provide an economic signal which will encourage them to correct power factor on site. As pointed out in Section 3.2, kVA is provided for in the metering of customers with consumption of 735 MWh or greater.

4.3 Postage stamp pricing structures

The postage stamp approach that has been used to date for the recovery of TUoS general and common service charges is in fact comprised of two separate activities. The AER's discussion blurs the distinction between these elements:

- The *allocation of costs* to individual connection points, based on either an energy allocation (the default arrangement), or a demand allocation (used at some high load factor locations to reduce the allocated cost); and

- The *price structure* used for the recovery of the allocated cost.

It should be noted that very significant cost allocation changes can arise from a change from energy to demand based allocation, which can particularly impact large industrial customers. Furthermore, it should be noted that this cost component is not covered by the transmission side constraint and therefore any change to the allocation approach would under the present rules flow directly to the customers concerned in the year in which the change was made.

Option	Description	Comment
1	Energy and capacity based prices and charges are calculated and the one most favourable to the user was applied, with users' maximum demand capped, in the event of a capacity allocation.	Current approach works satisfactorily and is understood by large users concerned. Large end user network *price structures* in conventional forms can be used to comply with this requirement.
2	Energy only pricing structure.	Energy ***allocation*** would impose very significant price shocks on existing energy intensive industries that have a capped demand charge. Price change is not subject to 2% side constraint.
3	Capacity only based price structure	Capacity ***allocation*** would impose a price shock on low load factor users. Capacity ***price structure*** cannot be directly incorporated in most customer prices.
4	Demand based postage structure using one of the forms of demand proposed for the locational component.	All of the AER's demand based price structures have significant disadvantages, as outlined in Section 4.2.

Q15. Which of the *postage stamp* pricing structures discussed would be most appropriate, taking into consideration the desirability of consistency across the NEM, particularly for customers with operations in multiple jurisdictions and the desirability of signalling efficient investment and network utilisation decisions?

The AER has made no case for a change to the current pricing allocation and pricing structures. It must be remembered that the postage stamp allocation is intended to recover a proportion of network revenues in the least distortionary manner, with the price signal to affect consumption arising from the locational component.

The current option is considered to provide appropriate arrangements by providing relief from the energy based allocation to large energy intensive users, in return for a capacity based price that can be implemented with conventional end use price structures.

Q16. Are there any implementation issues which might affect the adoption of any of the postage stamp pricing structure options discussed?

Q17. To what extent would any of the postage stamp options disadvantage any group of market participants?

Any alteration to the current pricing allocation will affect customers in different ways. The cost allocation is a zero sum game and a reduction in one customer's price translates to an increase in another's.

An energy based allocation of costs will penalise energy intensive industries with high load factors, regardless of the price structure applied to the allocated cost. This effect can be substantial, as the allocated component of TNSP revenue will commonly exceed the locational component. Consider an industry with a load factor of 0.9, at a connection point where the average load factor is 0.6. This customer will receive an energy allocation equivalent to 150% of the demand allocation. This is likely to amount to a 25% difference in the total TUoS allocation. Moreover, as noted above, this component of cost is not subject to side constraints.

It will be important that, in the event that the AER decides to alter the current pricing allocation, there adequate consideration be given to transitional arrangements. Potentially, in the event of a significant change in the pricing allocation grandfathering arrangements and streamlined prudent discount processes would be required.

Q18. If the options for the postage stamp pricing structures are not appropriate, practical, or create excessive additional implementation costs, what alternative postage stamp structures could be considered?

No need is seen to depart from the current arrangements for the allocation and structure of postage stamp charges.

Q19. If a capacity based price structure was used to recover costs associated with the adjusted non-locational component of *prescribed TUOS services* and *prescribed common transmission services*, is the use of kVA or MVA (as opposed to kW or MW) appropriate and practical?

For large end use customers, EA already applies a kVA price structure to demand and capacity components.

For smaller end use customers (less than 735 MWh consumption) kVA price structures are not supported by Type 4 and higher metering classifications.

See the response to Question 14 regarding the economics of power factor correction at different voltage levels in the network

Q20. If the use of historical usage or demand data is required and is not available or the data has changed significantly would it be appropriate to use current data?

In carrying out the pricing allocation it is necessary to have flexibility in the use of historical and forecast data, to cater for the eventuality of new connections to the network.

4.4 Asset classification

Q21. What additions or deletions should be made to the list of transmission asset types directly attributable to *prescribed entry services*?

Q22. What additions or deletions should be made to the list of transmission asset types directly attributable to *prescribed exit services*?

No need for alteration of the existing categories of assets types is recommended.

Q23. Should a cost sharing mechanism be established for assets which are used as both *prescribed entry services* and *prescribed exit services*?

A form of cost allocation already is used at the distribution level, to apportion the cost of transmission connection assets amongst large customers connected at a connection point. The CRNP approach, with customer loads modelled separately in the pricing analysis (yielding demand shares) is used.

Q24. What additions or deletions should be made to the list of transmission asset types directly attributable to *prescribed common transmission services*?

Q25. What additions or deletions should be made to the list of transmission asset types directly attributable to *prescribed TUOS services*?

No need for alteration of the existing categories of assets types is recommended.

4.5 Information disclosure

Q26. What information, associated with a pricing methodology, is likely to have confidentiality issues, and how can the information be presented to maximise transparency of the process in relation to these matters?

Some of the information proposed by the AER to assess a TNSP's pricing methodology is currently, and needs to be kept, confidential to the regulator and end use customers involved. In particular, any information pertaining to a single customer's price or connection, or information which could be used to infer the price of a single customer, must not be published.

It follows that the prices at certain locations on the network where there is a single large customer, or a limited number of large customers, should not be made publicly available. Nor should the details of negotiated discounts with customers be specifically identifiable.

Clause 6A.25.2(e) requires the pricing methodology guidelines to "specify or clarify ... those parts (if any) of a proposed pricing methodology or the information accompanying it, that will not be publicly disclosed without the consent of the Transmission Network Service Provider".

This Rule is of concern, in that it suggests that the AER may publicly disclose anything else (whereas the AER has confidentiality obligations under s44AF TPA, albeit diluted by NEL Pt 3 Div 6, but which still contains procedural requirements and consideration on a case by case basis). Such unfettered freedom to publish is inappropriate.

The AER does, however, use the Rules-defined term "confidential information", which also does not appear to be appropriate, as this term only covers information provided to Registered Participants or NEMMCO (and not by Registered Participants to the AER).