EnergyAustralia's submission to

Australian Energy Market Commission

Review of the Electricity Transmission Revenue and Pricing Rules

Pricing Paper

23 December 2005

Energy

Contents

1 Introduction

EnergyAustralia welcomes the opportunity to respond to the Australian Energy Market Commission's (AEMC's) Consultation Paper: *Review of the Electricity Transmission Revenue and Pricing Rules: Transmission Pricing Issues Paper*.

EnergyAustralia's network, by definition, contains transmission elements within the predominantly distribution network. The transmission component of EnergyAustralia's network comprises 12% of the total network in terms of revenue and has the dual role of supporting the main transmission grid in NSW as well as supplying EnergyAustralia's customers. Customer connections to EnergyAustralia's transmission network primarily consist of large loads, with fewer generator connections than other service providers. As both a transmission and distribution service provider, EnergyAustralia faces two diverse regulatory principles and processes for its transmission and distribution networks. Transmission and distribution networks are different in a number of operational ways but are comprised in essence of long lived infrastructure assets that are generally indistinguishable.

At the outset, it should be noted that the responses provided in this submission are made in the context of the current revenue cap form of price control (with adjustments for pre-defined factors) being maintained. The impact of alternative forms of price control, if any, on the questions posed in the Pricing Issues Paper has not been considered in detail at this stage.

The Pricing Issues Paper canvases a comprehensive range of pricing issues, commencing with the fundamental question of whether transmission services should be regulated at all. The AEMC is to be commended for this "back to basics" approach that ensures all issues are effectively on the table. The paper also appears to have taken account of regulatory issues raised in the wider energy market, including the reviews of the Third Party Access Regime and the National Gas Access Regime.

However, in contrast to some other energy industries, the dominant view from suppliers in the electricity transmission industry is that the current regulatory framework is in more need of fine tuning than radical reform. The industry supports the key themes of striving for greater certainty, clarity and consistency of the regulatory arrangements and aligning the interests of transmission providers with those of grid users.

EnergyAustralia has been involved in discussions with the Transmission Network Owners (TNOs) and there is general consensus on the key positions taken in this submission. For instance, there is general support for the following:

- focussing on clarifying the status quo, as opposed to a fundamental overhaul of existing arrangements;
- it is necessary to maintain an adequate level of prescription in the Rules covering revenue allocation and the price setting process, while granting Transmission Network Service Providers (TNSPs) flexibility over actual pricing structures;
- proposed changes to the existing regime should be based on a consideration of all economic costs and benefits, including distributional consequences, and appropriate transitional arrangements should be established where necessary; and
- ensuring that TNSPs are able to recover all economic costs incurred.

However, EnergyAustralia is in a unique position among other TNSPs as it is predominantly a distribution business. Therefore, it is well placed to provide more detailed comments and experience on issues such as avoided TUoS arrangements. Furthermore, to be consistent with key cost-reflective and demand management aspects of its distribution pricing strategy, EnergyAustralia's comments may place more emphasis on the importance of sending correct economic signals than perhaps other TNOs, whose primary focus could be ensuring revenue recovery, minimising risk and providing adequate transitional arrangements. In this context, EnergyAustralia has provided detailed comments on an efficient TUoS allocation regime in this submission, with the intention of contributing to the debate and proposing an efficient regime from first principles. It must be remembered however that ultimately, under a revenue cap form of regulation, ensuring revenue recovery per se should always be the primary objective.

2 Executive Summary

The following is a summary of EnergyAustralia's key positions in response to the issues raised in the AEMC's Transmission Pricing Issues Paper:

General principles

- EnergyAustralia is keen to encourage the development of arrangements which would permit the regulation of its combined distribution and transmission business as a single entity, with a single form of regulatory control and the internal partition of its transmission costs for pricing purposes.
- The comments provided in this submission are made in the context of the current revenue cap form of price control (with adjustments for pre-defined factors) being retained. The impact of alternative forms of price control on transmission pricing has not been considered.
- In broad terms, the existing transmission pricing arrangements outlined in the Rules are satisfactory. Hence the review should focus more on clarifying the status quo (to prevent diverse interpretations of the Chapter 6 Rules), rather than introducing fundamental reforms.
- Any major changes to existing arrangements must be based on a demonstrable net benefit.
- For proposed Rule changes that relate to the detailed pricing functions of TNSP businesses, the AEMC should establish working groups with TNOs to ensure that any changes reflect actual industry practice.
- Appropriate transitional arrangements that properly recognise pre-existing agreements (such as contracts) should accompany changes to the current regime.
- Description versus prescription:
  - EnergyAustralia is satisfied with the current level of prescription in the Rules as it provides predictable outcomes that customers are entitled to expect. However, there is room for further clarification of some ambiguous areas in the Rules;
  - the current degree of prescription serves as a useful guide for price negotiations with users (who are informed and have countervailing power in the market place);
  - it is important to clarify pricing objectives and key messages in the Rules; and
  - a shift towards less prescription and greater transparency is not favoured as this would lead to a multitude of complex arrangements for each TNSP. This is unlikely to offer an improvement over present arrangements.
- TNSPs should be kept economically neutral as a result of any changes to transmission pricing arrangements, through the recovery of any implementation costs and/or discounts.

Scope of regulation

- The Rules should specify which transmission services are prescribed. The Rules should also contain a set of criteria for assessing whether a service should be treated as excluded.
- The AEMC should develop of set of criteria in the Rules for assessing the potential for excluded services. As part of its revenue and pricing proposal, the TNSP should be able to nominate to the AER which services could potentially be excluded. In the event of a dispute, the AER would refer the matter for AEMC for a final decision.
- Transmission connection services may be contestable and so appropriately dealt with through lighter-handed forms of regulation.

Economic efficiency

- Consistent with its distribution pricing strategy, EnergyAustralia believes that, in principle, transmission pricing should be viewed as another tool to send appropriate economic price signals based on the true cost of usage, rather than simply a means to recover revenue. However, it is appreciated that the effect of the transmission price signal is often significantly watered down by the time end user prices are set, particularly for smaller customers.

- The modified CRNP framework provided in the Rules is believed to have certain economic advantages over the conventional CRNP approach, as allowing the usage component proportion to vary could act as a proxy for congestion pricing. The Rules should ensure both CRNP methods are treated on a level playing field, while precluding individual customers from selecting modified CRNP. The Rules could also provide more guidance on the proportion of usage charge applicable at various utilisation levels under modified CRNP, in order to minimise potential disputes.

- In line with the market development objective of the NEM, transmission price signals should not dampen investment in potential new generation assets through imposing high up-front capital contributions based on complex and potentially subjective deep connection charges.

TUoS allocation

- EnergyAustralia supports the reallocation of TUoS charges to all users (both generators and load customers) in principle, to produce more equitable and efficient pricing outcomes. However, given the current situation, transition arrangements and distributional effects should be considered.

- There would be merit in considering a similar TUoS locational charging system to that existing in the UK, based on a number of different pricing zones for both generators and loads. This may remove some of the complexity associated with the current CRNP methodology. Such a scheme, in conjunction with consistent pricing arrangements within the distribution networks, would obviate the need for avoided TUoS payments, as payments to embedded generators would be an implicit feature.

3 Requirements for Regulation

3.1 Dilution of Transmission Prices through DNSPs

Q1. Should transmission prices be regulated and why?

Q2. If regulation is required what form should this take? For example, should it be less prescriptive and involve greater transparency or be more prescriptive?

Q3. What role, if any, should the AER have in determining the nature and form of price regulation?

A1: For prescribed transmission services, EnergyAustralia acknowledges the need for ongoing regulation due to the presence of monopoly characteristics. For transmission services where TNSPs posses less market power (eg. connection services), permitting contestable market forces to work or light-handed regulation is more appropriate. Light-handed regulation could take the form of transparency in the disclosure of negotiation and pricing principles, in a similar vein to the Independent Pricing and Regulatory Tribunal's (IPART's) current treatment of excluded distribution services in NSW.

A2: The current level of prescription in pricing contained in the Rules is considered appropriate, although further clarification is required in some areas. Greater transparency would not make the process any simpler, as complex pricing arrangements are necessary for an equitable solution to allocating the costs of a shared network. Prescription is also helpful in managing negotiations with large, informed users of the transmission network.

A3: As a general rule, the AER should not have discretion in determining the services that it regulates. The principle of separation of powers should apply. If there is to be discretion in form of price regulation, then the TNSP should instigate this change in this first instance, not the AER.

3.2 The NEM Objective and Rule Making Test

Q4. Bearing in mind the NEM objective, should economic efficiency of the Rules be the focus or should it also have regard to the distributional consequences of Rule changes?

Q5. If the NEM objective should have regard to distributional consequences of Rules changes, how should these be taken into account?

A4: It is essential for changes to the Rules to consider distributional consequences in the pursuit of economic efficiency. Any robust analysis of the effects of a Rule change on economic efficiency will typically consider the distributional consequences as a matter of course. Distributional effects are important because many TNSPs have existing contracts in place with network users that may be affected. Consideration of transitional arrangements will be particularly important in the case of any change to pricing allocation.

A5: If side constraints are to be institutionalised, the transitional guidelines in Clause 6.5.5, which currently imposes a 2% cap on the annual change in usage charges, may not be sufficient to allow a transition to efficient prices within a reasonable timeframe. The AER is urged to consider the adoption of a larger rate of change. As a reference point, the price change cap could be in line with allowable distribution price changes (ie., CPI plus 4.5%) – a limit of CPI plus 5% is therefore considered reasonable. The overall effect of the price change will of course be significantly watered down for the majority of end use customers, as transmission charges typically represent only a minor component of an average end user bill.

4 Current Transmission Pricing Regime

4.1 Connection Charges

Q6.	Is the allocation of network costs between the connection and shared network categories in the Rules broadly appropriate? If not, how could it be improved?

A6: The approach to cost allocation in the Rules is considered reasonable and in EnergyAustralia's experience has allowed workable solutions to be developed for specific instances.

4.2 Common Service Charge

Q7.	Should a common service charge be maintained or should these costs be incorporated into another charge? If not, how should common service costs be allocated or incorporated into other charges?

A7: The common service charge covers costs which are unable to be allocated directly to a network user or location and this cost category will need to be maintained in its present form. This cost component would be most efficiently recovered from customers, but the "capacity allocation" approach in the Rules is considered to provide a more reasonable allocation of costs. The costs of a transmission business are all associated with providing adequate and reliable capacity, rather than energy delivery, and should be recovered on the basis of that form of allocation.

EnergyAustralia therefore believes the capacity allocation approach in the Rules should be made mandatory, subject to transitional arrangements to limit price changes to existing customers.

4.3 Usage Charges

Q8.	Should generator and MNSP use of system charges remain a matter for negotiation with the TNSP or should they be prescribed in the Rules?

A8: The existing transmission pricing arrangements are deficient, in that there is no charge for the use of the network to generators connected to that network. These arrangements were set up at the time of disaggregation of the industry and establishment of the State Electricity Markets in 1996. The absence of a locational signal has created an advantage for the incumbent generators compared with any new entrant generator connected to either the transmission or distribution network. Whilst in economic terms the transmission investment is a sunk cost, the recovery of its costs from generators is necessary for efficient investment and operational decisions to be made going forward.

EnergyAustralia has consistently supported the recovery of a component of TUoS from existing generators, on the basis of providing equity between existing generators and new generation and demand management options, regardless of whether they are located in the transmission network or embedded within a distribution network. EnergyAustralia notes that this was the original intention when the pricing arrangements were first being established, although the decision was reversed prior to the finalisation of the arrangements. The fundamental approach for both customers and generators should be that each pays the Long

Run Marginal Cost (LRMC) associated with their use of the network. The fact that existing generators were given a "free ride" from the formation of the market needs to be reversed.

EnergyAustralia therefore supports the pricing approach for generators being embedded within the Rules in the same way as for load customers.

For an example of an efficient network pricing allocation at both transmission and distribution levels, the AER is encouraged to consider the pricing arrangements put in place in the United Kingdom by Ofgem. These arrangements include:

- Approximately 1/3 of transmission revenue is collected via generator use of system charges;
- The predominant flow of power in the UK is from generating centres in the North and centre of the country, to major load centres in the South;
- TUoS charges for generators are in 14 zones, with the highest priced in the North, and with significant credits applying to generators in the South;
- TUoS charges for load customers are also zonal, being highest in the South and lowest in the North; and
- Charges can also apply for use of the distribution system, by generators embedded in the distribution network.

It is acknowledged that the UK approach would require some adaptation for the unique configuration of the Australian national grid. However, it is considered that such an approach would deliver more efficient pricing signals and eliminate the need for the present avoided TUoS arrangement, which is simply an unstable cross subsidy to embedded generators.

Q9. If a modified CRNP usage charge is to remain an option:

- should the Rules prescribe the criteria for the AER to accept implementation of modified CRNP?; and
- should any network customer (rather than just the TNSP) be able to request that the modified CRNP methodology be implemented?

A9: The modified CRNP approach has the potential to provide more efficient price signals than conventional CRNP, as it contains an element of congestion pricing (since the component of usage charge would not remain static at 50% but increase as elements of the network became more fully utilised). In this way, prices rise as utilisation increases, signalling the need for augmentation, and then fall once augmentation is complete and spare capacity exists. This provides the marginal cost "sawtooth" that can promote greater economic efficiency. Standard CRNP provides TNSPs with a blunter tool to send the appropriate price signals.

Currently, the Rules impose a bias against the use of modified CRNP due to the AER approval requirements, which do not apply for standard CRNP pricing. This is unjustified, especially considering the arbitrary basis for the 50% usage charge under standard CRNP in the first place and the potential economic superiority of modified CRNP to provide congestion price signals. Standard CRNP can effectively be construed as a subset of modified CRNP pricing, so the two methods are not mutually exclusive. Therefore, CRNP and modified CRNP should be treated more evenly in the Rules to allow the TNSP flexibility to select the most appropriate method.

To provide guidance to market participants and to minimise potential disputes, the Rules could map out a scale of capacity utilisation levels and the corresponding proportion of the usage charge component applied by TNSPs under a modified CRNP regime.

The Rules should preclude individual network customers from being able to select modified CRNP; rather the Rules should allow the TNSP discretion in selecting the pricing and allocation methodology that achieves appropriate outcomes for the network as a whole. The altered pricing allocation of a fixed revenue would affect customers in different ways and those that might benefit would naturally seek its adoption, to the detriment of those that would see higher prices.

Q10. How well do the CRNP and modified CRNP methodologies accord with efficient pricing principles? Could simpler approaches be applied to produce similar outcomes?

Q11. If the CRNP and/or modified CRNP methodologies were to be retained are the descriptions of the methodologies in the Rules sufficiently detailed and clear? If not, how could they be clarified?

A10: Any pricing allocation involves compromises, but EnergyAustralia believes the existing TUoS pricing provided by the approach in the Rules provides reasonably efficient usage prices for load customers. Although it may appear complex to outsiders, the CRNP approach incorporates existing techniques used by TNSPs for planning purposes (ie. load flow analysis) and TNSPs have already invested in systems and processes to administer it. While it is not put forward as a panacea, the CRNP approach was considered superior to even less transparent alternatives at the time of its original development and has been the subject of an extended review by NECA.

The pricing software (TPRICE) has been designed to allocate a proportion of network costs to generators as usage charges and this facility would readily permit a more efficient pricing regime where existing generators were allocated a proportion of network cost in proportion corresponding to their usage of the network.

However, EnergyAustralia believes that ensuring adequate prescription of whatever pricing regime is adopted (in order to provide clarity to market participants), takes precedence over the issue of maintaining CRNP per se. Indeed, the zonal pricing regime suggested in the response to Q8 could involve a lower reliance on CRNP pricing.

A11: There have been some areas of detail in the cost allocation where interpretation has been required. If CRNP is to be retained, it is suggested that the AEMC should convene the TNSP pricing practitioners to compare and contrast their practices and identify those areas where clearer description in the Rules would assist in providing uniformity. As a general principle, the AEMC will need to consult with TNSPs when proposing Rule changes that relate to the fine detail of the price-setting process.

4.4 *TUoS Discounts*

Q12.	Is it appropriate to provide scope for TUoS discounting in the Rules?
Q13.	If so, could the existing arrangements be refined and how?

A12: In general, price discrimination may be desirable where it aids economic efficiency. With a mechanical price setting process such as the CRNP allocation set out in the Rules, situations will inevitably arise where a discount on TUoS is required to avoid uneconomic bypass to the network caused by the pricing allocation. There will also be situations where other customers would still be better off with a customer paying reduced TUoS rather than not contributing at all. The existing ACCC guideline on TUoS discounts[1] provides useful guidance on the treatment of such instances and is considered to be generally appropriate.

The circumstances pertaining to a discounted charge can vary greatly and it is believed that only the general principles should be incorporated within the Rules. More practical and detailed guidance would be appropriately covered by the issue of Guidelines by the AER.

A13: The existing Guidelines on discounted charges would benefit from greater clarity in the areas of:

- The allocation of the required work (it is envisaged that the proponent should be responsible for the majority of the workload, rather than the TNSP, as the proponent instigates the request);
- The high level principles – for instance, full details of the proposed alternative to be disclosed and the alternative supply option must be technically, economically and practically feasible;
- Imposing deadlines on the AER to ensure that discount applications are dealt with in a timely manner; and
- Permitting TNSPs to recover the full costs from other customers - EnergyAustralia has had experience under IPART's regime where it did not recover full costs.

4.5 *TUoS Rebates*

Q14.	Is it appropriate to prescribe arrangements for TUoS rebates in the Rules? If so, could the existing arrangements be refined and how?
Q15.	Do the current pricing arrangements appropriately cover alternatives which contribute to the avoidance or postponement of transmission augmentation?
Q16.	Should TUoS rebates also apply to generators connected to the transmission network, DSM or other non-electricity options? Does this depend on whether generators generally pay shared transmission costs?

A14: In the response to Q8 and Q10, EnergyAustralia has outlined what it believes would be a more efficient cost allocation process, which would involve the allocation of some network costs to generators, in proportion to their use of the transmission network. This needs to be accompanied by a DUoS arrangement for embedded generators, as now exists in the United Kingdom.

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1 Guidelines: Statement of Principles for the Regulation of Transmission Revenues - Guidelines for the Negotiation of Discounted Transmission Charges, Australian Competition and Consumer Commission, 3 May 2002.

These measures, where each participant, whether customer or generator, would be exposed to a price reflecting the long run cost of their use of the network, would obviate the need for the existing avoided TUoS regime, which is considered to be both unstable and inappropriate. Where a generator was to contract to genuinely enable the deferral of network investment, its network price (TUoS and/or DUoS) would potentially be negative, as is now the case in the UK.

A15: The adoption of usage based CRNP, mentioned in A9, would assist in delivering TUoS usage charges which reflected a congestion component, with locational prices increasing as the utilisation increased and need for augmentation of the network drew closer.

A16: The existing avoided TUoS charges are simply a cross subsidy paid to embedded generators. This arrangement is both inefficient and unstable.

- *Inefficient:* under the current TUoS allocation regime for generators, real locational transmission costs have been removed, distorting generators' cost structures and therefore bidding strategies. Existing generators have a cost advantage over new generators, regardless of location. The cost of existing generators' transmission infrastructure should be reflected in their bids into the energy market, as a generator's marginal cost should reflect the full cost of supply. Instead, this cost is currently transacted via network prices and smeared across all customers. The current avoided TUoS payments represent the locational component of TUoS for loads (including the smeared generator cost) and do not reflect the locational signal that should be provided for embedded generators.

  EnergyAustralia's experience in relation to one connection inquiry in the inner Sydney area (which has not yet proceeded) involved a generator of over 300MW. The connection of this generator was technically possible to the nearby transmission network at 132 kV, or to the distribution network at 33 kV. In the case of the distribution connection, the generator would have qualified for annual avoided TUoS payments of several million dollars (ie. sufficient to offset an investment of a few tens of millions of dollars). The current Rules provision has the potential to very significantly distort the proponent's choice of connection point.

- *Unstable:* EnergyAustralia has had first-hand experience of the instability of the avoided TUoS regime, through the arrangements applying at a particular generator within EnergyAustralia's Network (further details could be provided if requested) is close to the magnitude of the connected load in this area. Avoided TUoS payments are based upon the locational TUoS charge at the transmission connection point. This charge is calculated as an annual cost from the allocation process (which is demand based and so picks up the loading at periods when the generator is not operating) divided by the net energy flow at that location. It should be noted that the structure of the TUoS usage component imposed by the TNSP has an influence on this outcome.

  If the generation in an area were to progressively approach the magnitude of the load, the allocated cost at that location would be divided by a progressively smaller net energy flow and the usage rate would increase asymptotically. Avoided TUoS payments to the generators in the area would be based on the net rate and increase in this asymptotic fashion. The higher rate applied for the purposes of avoided TUoS provides the generator with a payment which has been artificially increased.

  Moreover, as the particular generator referred to above is in the generation-rich Upper Hunter Valley of NSW, its output adds to the flows that are transported southwards to Sydney and other major load centres by the main transmission network. Rather than qualifying for an artificially inflated avoided TUoS payment based on the net usage rate, the generator should be contributing to the need for TransGrid's planned 500kV upgrade of its transmission network at a substantial cost, which would be passed on to customers.

The extension of an avoided TUoS approach to generators connected to the transmission network is strongly opposed. Instead, an efficient generator pricing regime such as that in place in the United Kingdom is preferred.

However, if such an efficient generator pricing regime is not introduced in Australia, the existing avoided TUoS regime for embedded generators could be improved by the introduction of a two tier regime, where the avoided TUoS payment methodology varies with generator size.

The current avoided TUoS regime passes on the usage based charge at a connection point to an embedded generator. This may be a reasonable compromise for smaller generators. However, as illustrated above, the mechanical calculation of avoided TUoS has considerable potential to influence the connection voltage, which would be an unintended uneconomic outcome.

It is therefore proposed that for embedded generators above a certain size, the actual avoided TUoS should be used. The local TNSP would need to provide details of planned network augmentation in the area and any associated deferral caused by the presence of the generator, to determine this payment. An appropriate threshold for the larger generators is considered to be 10MW or more. This would align with the Rules requirements in relation to individual loss factor calculation for generators and reflects the level where embedded generation can have a significant effect on future network augmentation.

5 Efficiency and Transmission Prices – Key Concepts

5.1 Long Run Marginal Costs and Efficient Pricing

Q17.	Should transmission pricing arrangements principally seek to promote efficiency in the short or long run?
Q18.	If transmission pricing arrangements should consider both the short and long run, what approach should the Commission take to determine the appropriate balance between these aims?

A17: EnergyAustralia has long held the view that in the context of network infrastructure businesses, pricing needs to reflect the marginal costs of increasing output (ie. long run marginal costs). These long run costs, if reflected in network prices, provide signals as to the cost of usage, while at the same time provide the price stability necessary to enable the users of the network to make informed and appropriate choices concerning their investment and operational programs. The pricing arrangements for transmission should thus place priority on long run price signalling.

The AEMC must adhere to the NEM objective, which states in the NEL that the electricity market objectives must consider both efficient investment in (ie. long run costs) and efficient use of (short run costs) electricity services. Similar wording has been proposed for an objects clause to be inserted in the Gas Code. In its review of the National Gas Access Regime, the Productivity Commission discussed the importance in price setting of balancing both short run (largely concerned with maximising allocative efficiency) and long run (dynamic efficiency) considerations. The review acknowledged the pitfalls of setting access prices too low in the short run, as this encourages additional usage leading to a long run reduction of supply. This would ultimately reduce consumption, more than offsetting any temporary gains from lower initial prices.

The Productivity Commission also considered the issue of long run and short run considerations in its review of the National Access Regime, where it recommended that "access prices be set so as to generate revenue across a facility's regulated services that is at least sufficient to meet the efficient long-run costs of providing access to these services"[2] Recovering long run costs is essential to uphold the regulatory principle of financial capital maintenance, where a TNSP is able to recover the full costs of prudent investments in net present value terms.

The electricity market is currently based on short run costs and its settlement includes the cost of losses, based on the product of long run percentage estimates, short run prices and quantities. To the extent that there are synergies between short run market price signals and short run network considerations (e.g. outage conditions), pricing which can induce customer behaviour in both a short and long run sense is appropriate. This consideration forms the base for EnergyAustralia's trial of Dynamic Peak Pricing, which will be underway during December 2005. This form of pricing has the potential to pass through both long and short run price signals (through a Time of Use basic price with a higher Dynamic Peak price for short periods).

A18: It is considered that TUoS pricing arrangements should focus on long run considerations, by passing on the costs of transmission network infrastructure through prices which, to the

[2] Productivity Commission 2001, *Review of the National Access Regime*, Report no.17, AusInfo, Canberra.

greatest extent possible, contain a price signal that aligns with the long run costs of the network.

It must be remembered that TNSPs do not directly supply the great majority of customers, which are connected to distribution networks. The price signals by TNSPs must be capable of being passed through (preferably preserving the price signal) to end use customers and this is largely influenced by existing metering arrangements. There is seen to be little benefit from implementing complex price signalling at the transmission level (especially short run cost signalling) that cannot be passed through to the load customer by the distributors.

6 Relevant NEM Context

6.1 Regulatory Test

Q19. To what extent are existing signals from other aspects of the NEM arrangements (or requirements from regulatory settings outside the NEM) sufficient to promote efficient behaviour by actual and potential consumers and producers of electricity in the short and long run?

A19: EnergyAustralia's experience with the development of its transmission network has been related to the provision of supply to customers, rather than the connection of generators.

Notwithstanding this, as a general principle, EnergyAustralia is concerned that the current market signals may not lead to economically efficient investment by participants. The fact that the NSW region of the NEM is forecast to require generation investment within 3-4 years, and there are no committed projects, fuels this concern. The latest NEMMCO supply-demand forecasts[3] predict that known NSW generator reserves will dip below the minimum reserve level in 2008/09. Even if minimum reserve levels are met, the negative reserve margin set for NSW requires 290MW to be imported from Queensland's surplus generation capacity. Such a supply arrangement itself is potentially unstable, as it is based on the assumption of diverse weather patterns between the two states, and may be construed as evidence of ill-timed and/or ill-located generation investment.

Potential electricity supply interruptions loom even closer in the combined Victoria/South Australia region, with capacity expected to fall below the reserve in the 2005/06 summer. The arrival of Basslink in 2006 is set to provide only a temporary reprieve before load growth erodes the extra capacity below reserve again from 2007/08.

Whilst outside the scope of this current review, the NEM design itself is believed to need review. It may well require some form of capacity payment to elicit the necessary generation investment. This development may imply some form of central planning style intervention, rather than leaving electricity supply purely to the "invisible hand" of Adam Smith.

As far as transmission locational signals are concerned, generators, in deciding when and where to locate, may give more weight to factors such as proximately to fuel sources and pool prices than to transmission costs. Other existing features of the market discussed in the AEMC's Pricing Issues Paper such as the regulatory test and the presence of non-firm generator access rights will also have an impact. However, to operate efficiently, the market should fully reflect all related economic costs. Consideration of transmission price signals may well affect the investment and locational decisions of NEM participants for marginal projects.

[3] NEMMCO 2005, *Statement of Opportunities for the National Electricity Market*, NEMMCO, Melbourne.

6.2 Distribution Network Pricing Arrangements

Q20. Given current distribution network pricing arrangements, is it appropriate to prescribe transmission pricing structures in the Rules?

Q21. If so, should prescription be limited to prices for particular network users?

A20: The existing Rules requirement is non prescriptive in relation to the structure of the transmission usage based charge. The particular circumstances of each TNSP (its capex drivers) and customers (whether end use or distributor, type of metering, ability to respond or pass on the signal) need to be considered in framing an appropriate price structure. These factors have led to the TNSPs adopting a diverse range of pricing structures – any moves to unify price structures will cause reduced flexibility and price shocks to some customers, with no material benefit.

It is considered that the price structure is best left to the individual businesses concerned and that greater prescription in the Rules would stifle more innovative arrangements that might be appropriate. Some general principles might be useful as a form of guidance for TNSPs, but these should be contained within guidelines issued by the AER, rather than the Rules. As outlined in A19, a key factory in setting the structure of TNSP's prices should be the ability of distributors to pass these on to end use customers.

A21: EnergyAustralia does not believe prescriptive charge structures should apply to any network user.

7 Allocation of Regulated Revenue Across Transmission Users

7.1 Connection Charges

Q22.	Should NEM connection charges continue to be based on a shallow connection approach or should a deep connection approach be adopted?
Q23.	If a shallow connection approach is broadly to be maintained, are there any circumstances where connecting parties should pay for up or downstream upgrades to the shared network?
Q24.	If a deep connection approach is to be adopted in the NEM, how should it be formulated?
Q25.	Is a deep connection approach compatible with the open access transmission regime of the NEM (which is not a subject of the present Review)? If so, how should potential "free-rider" effects be managed?

A22: There have been a limited number of connection applications for EnergyAustralia's transmission network since market start and these have been approached in a consistent manner to connections to the distribution network. That is, the provisions of IPART's capital contributions policy have been applied[4]. EnergyAustralia is generally satisfied with the operation of IPART's capital contribution determination, which allows for the recovery of direct dedicated connection costs in all cases and in this way facilitates locational price signalling for customers. EnergyAustralia also notes the additional complexity and subjectivity that a deep connection approach would introduce into the pricing process.

A23: Occasionally, there are circumstances where the recovery of only direct connection costs would lead to inefficient and inequitable outcomes. IPART's distribution determination makes provision for the recovery of deep network costs in two circumstances - large load customers (greater than 50% of existing capacity) and rural extensions. The policy also caters for the partial refund of a capital contribution if a second customer was to make use of the deep contributed asset within a seven year time frame.

EnergyAustralia suggests that a uniform capital contributions arrangement similar to that in operation in NSW is leading to generally efficient outcomes and would be appropriate for the NEM (perhaps with some minor modifications to adapt for transmission circumstances). Such a policy needs to be even-handed in its application to generators and loads and be backed up by use of system charges for both parties which efficiently recover the cost of shared assets that might be provided for an individual customer or generator connection through TUoS charges.

The capital contributions policy should be determined by the AER in accordance with overarching principles incorporated into the Rules, to permit variation of the policy as may be necessary for unforeseen circumstances. The policy should also deliver consistent outcomes at both transmission and distribution levels of the network.

EnergyAustralia proposed in its submission to the AEMC's Transmission Revenue Issues Paper that the Rules should enable the pass through of unforseen and material events that

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4 Capital Contributions and Repayments for Connections to Electricity Distribution Networks in New South Wales Final Report, Independent Pricing and Regulatory Tribunal of NSW, April 2002

may arise within a regulatory period. This includes unforseen customer connections, such as those that occurred in the UK due to the marked increase in connections from renewable generators stemming from a government policy change. EnergyAustralia proposes that the materiality threshold should be the lower of either 1% of annual revenue or $3 million. The materiality threshold should also allow for an aggregation of events that may individually be below the threshold, but cumulatively exceed the threshold.

It should be noted that there is a significant issue associated with capital contributions which impacts the TNSP's revenue requirement. Capital contributions and contributed assets are treated in an accounting sense as income in the year they are acquired, and tax is paid on that income. The associated taxation deduction takes place over the life of the asset (30-40 years) and there is thus a net loss which in NPV terms is in the order of 15%. Accordingly, the capital contributions policy can have a marked effect on the TNSP revenue requirement and allowance for the associated taxation payments is necessary in regulatory determinations.

A24: A deep connection policy is not advocated by EnergyAustralia, although there are some circumstances where the recovery of more than the shallow connection cost would be appropriate, as outlined in A23.

The introduction of a deep connection policy funded via capital contributions could potentially stifle much needed investment in the electricity market, thereby undermining a core NEM objective. This would act as a significant barrier to entry for new generators, further fuelling the current transmission cost inequity with existing generators.

Deep connection arrangements have principally been proposed to compensate for the lack of a TUoS price for generators connected to that network. The capital contribution arrangements and use of system charges are complementary and should be considered together as part of the review of generator charging arrangements.

A25: EnergyAustralia does not consider a deep connection approach to be compatible with the open access transmission regime of the NEM. Potential "free-rider" effects are considered to be best managed through an efficient TUoS pricing arrangement.

7.2 Shared Network Charges

Q26. Do signals from the regional pricing structure of the NEM, non-firm generator access and transmission investment arrangements provide efficient locational and operational signals to generators, loads and competing sources of energy supply?

Q27. Are there reasons why generators should make some contribution to shared network costs? If so, what approach should be used to determine the share of shared network costs should be paid by generators?

A26: Investment decision making in the Network should properly take account of the cost of losses. However, for most network investments (particularly at the transmission level) the cost of losses is a small component in the cost-benefit analysis.

Therefore, whilst the loss factors used in market settlements do have some effect in adjusting generator pool prices to reflect their "electrical distance" from the market, they represent but a small component of the cost of assets which were built to facilitate connection. Loss factors alone do not provide an adequate or efficient locational signal for generators. EnergyAustralia's response to Q19 provides more information on the need for additional generator locational price signals in addition to those provided under the current market arrangements.

A27: The response to Q26 above is at the heart of EnergyAustralia's support for a TUoS charging regime for generators. With regard to determining an appropriate generator share, there have been a number of approaches which were considered in the development of the existing pricing arrangements. The 50% of line related costs termed "TUoS General" was originally intended to be allocated to generators using the TPRICE software – instead it is allocated to load customers in the current arrangements.

Within each transmission region, it is possible to identify line assets which were principally constructed for, and still principally enable, generator connection. These assets (not all transmission assets) or a proportion thereof could readily be allocated to generators using the existing TPRICE software. In most cases, the magnitude of these reallocated costs will be dwarfed by other generator input costs (eg, fuel), so price shocks to generators are not expected to be substantial. The reallocation will, however, improve allocative efficiency through more cost reflective pricing for users of the transmission network.

In the long term, the development of arrangements like those put in place by Ofgem would be more appropriate and could lead to generators receiving payment where they were connected in constrained areas of the network.

EnergyAustralia acknowledges that any seismic shift in the cost allocation arrangements will have distributional consequences and implementation costs, which would need to be considered along with an examination of the economic efficiency benefits described by EnergyAustralia. Any significant modifications to the existing regime would naturally call for the establishment of appropriate transitional arrangements.

However, concerns about upsetting the status quo or the need for transitional arrangements should not be a deterrent to taking advantage of the one-off opportunity presented by the AEMC's review to fully examine ways to improve the efficiency of the market through an optimal cost allocation.

7.3 Alternative Allocation Approaches

Q28. Is the current shared network charging regime the best approach for achieving the NEM objective? If not, what improvements could be made?

Q29. Are there arrangements operating in other jurisdictions for the recovery of shared network costs that would be more appropriate for the NEM? If so, which jurisdictions and which aspects of their arrangements would be appropriate for the NEM?

A28: See responses to Q8, Q9, Q10, Q11 and Q27. In short, the existing charging arrangements for loads are thought to be relatively efficient. However, a charging regime for generators is required.

A29: Reference has been made in several areas to the arrangements in place in the United Kingdom. The UK pricing structure is believed to constitute current best practice and could be adapted for the Australian NEM.

7.4 Prudent Discounts

Q30.	How much discretion should TNSPs have to discount charges?
Q31.	Should TNSPs be entitled to recover the cost of discounts from other loads?
Q32.	Should any conditions for recovering the cost of discounts from other customers be prescribed in the Rules or left to the AER to determine? If so, what should be the general content of these Rules or AER discretions?

A30: The existing level of discretion and guidance on discounting charges provided by the ACCC is considered appropriate.

The relatively prescriptive pricing arrangements in the Rules need to be accompanied by a process to discount charges, where uneconomic outcomes would otherwise result.

A31: Yes, TNSPs must be able to recover the cost of discounts (provided in accordance with the Guidelines) from other load customers. In this regard, the current arrangements for transmission are far superior to those existing for distribution in NSW, as the IPART discount guidelines offer no recourse to recover discount costs from other customers.

A32: As stated in the response to Q12 and Q13, EnergyAustralia supports the incorporation of high level principles within the Rules and the issue of more detailed Guidelines by the AER.

7.5 TUoS Rebates

Q33.	Should avoided TUoS rebates be retained in the Rules or left for negotiation between the DNSP and connected party?
Q34.	Is the appropriateness of TUoS rebates contingent on whether generators pay shared use of system charges?
Q35.	If TUoS rebates are retained, what charges should they comprise?

A33: The benefit of retaining avoided TUoS rebate processes in the Rules is that both DNSPs and embedded generators have certainty over the outcome. DNSPs are not well placed to determine the costs actually avoided in the transmission network which supplies them, so this provision should be retained in the Rules as long as the avoided TUoS provisions remain.

A34: As mentioned in other locations in this response, EnergyAustralia is a keen supporter of the concept of generators paying a proportion of TUoS, with efficient prices such as those in place in the United Kingdom. With such a regime, the avoided TUoS provisions would become unnecessary.

A35: The response to Q16 outlines EnergyAustralia’s position on avoided TUoS payments.

8 Structure of Prices

8.1 Dynamic Efficiency

Q36.	To what extent is it necessary or worthwhile to prescribe transmission pricing structures in the Rules in order to promote the NEM objective?
Q37.	Would it be appropriate to provide guidance to TNSPs on what pricing should achieve instead of prescribing the structure? If prescription is required, which charges should have price structures prescribed in most detail?
Q38.	Should the degree of pricing structure prescription vary depending on the relevant class of network user paying the charge? If so, how could this be implemented?
Q39.	How much discretion over charging structures should be left to the TNSP and the AER?

A36: The current lack of prescription of transmission pricing structures in the Rules has enabled TNSPs to set prices for their network which reflect their individual circumstances. As indicated in the response to Q20, this is believed to be appropriate and there appears to be no compelling need for uniformity between TNSPs.

A37: It would be appropriate for the Rules to contain pricing objectives relating to the price structure. One important objective would be that TNSP prices be set with a view to facilitate their incorporation into the prices of load customers connected within distribution networks.

A38: See response to Q20 and Q21.

A39: EnergyAustralia believes that discretion over pricing structures should be the province of the TNSP, in accordance with principles set out in the Rules. The AER's role should be limited to ensuring that the principles in the Rules are being followed by the TNSP.

9 Pricing of Non-Prescribed Services

9.1 Alternative Approaches

Q40. Are the negotiation provisions in the Rules regarding prices for non-prescribed services appropriate? What difficulties (if any) have been experienced?

Q41. Should Rules provide criteria in relation to pricing outcomes for non-prescribed services?

Q42. Should a price monitoring regime be considered for non-prescribed services?

Q43. If so, what criteria would be appropriate? Would these be the same for all non prescribed services?

Q44. Are the current dispute resolution provisions in Chapter 8 of the Rules appropriate for disputes over pricing of non-prescribed services? What (if any) alternative dispute resolution processes may be appropriate?

A40: In common with other network providers, EnergyAustralia has published negotiation guidelines. There have been no difficulties to date in operating in accordance with the guidelines.

A41: EnergyAustralia considers the Rules should relate only to prescribed services.

Non-prescribed services are subject to varying degrees of competition and should be the subject of much lighter-handed regulation, such as price surveillance, or the publication of pricing principles. A regime such as that currently in place in NSW is considered broadly appropriate. The regulation of non-prescribed services should be the subject of guidance by the AER.

A42: The criteria for regulation (or otherwise) of non-prescribed services should vary depending on the level of competition (which will depend on the type of service and the number of providers in any geographic area). Currently, services outside the scope of the revenue cap can be categorised as either non-contestable services (such as negotiated generator and MNSP access charges) or contestable services (such as connections).

In general, market forces should be left to play, or at the least, much lighter-handed regulation should apply to the provision of contestable non-prescribed services. This could include a lighter-handed price approval regime (as is (notionally) the case for streetlighting services in NSW) through to a requirement to declare pricing principles and terms of trade (metering and connection services). Activities such as contestable metering, it is believed, have a sufficient level of competition to warrant no regulatory intervention.

Under the current Rules, the AER is responsible for determining whether sufficient competition exists for a service to warrant a more light-handed regulatory approach. As discussed previously, a fundamental principle of the regulatory framework must be that the AER should not have discretion in determining the services that it regulates – the Rules should be altered to reflect this stance. The TNSPs should propose the services to be subjected to alternative regulatory arrangements in the first instance through their price-service offerings.

A43: See above.

A44: The current dispute resolution provisions in Chapter 8 of the Rules may be acceptable for handling disputes over the pricing of non-prescribed services. The Chapter 8 process offers a staged approach to resolving disputes, with a strong initial focus on mediation and provisions for a more formal adjudication if necessary. This is likely to promote a faster, cheaper and more amicable solution to disputes than a more prescriptive and litigious-based process. EnergyAustralia has insufficient experience with the Chapter 8 process to be able to provide more detailed comments on how the process can be improved for transmission disputes.

10 Inter-regional Issues

10.1 Existing Arrangements

Q45.	Could the current provisions in the Rules regarding inter-regional TUoS payments be improved? If so, how?
Q46.	What are the impediments, if any, to reaching interregional agreements?
Q47.	Should the Rules provide criteria for determining the 'extent of use of a network'? If so, what criteria would be appropriate?
Q48.	Is there a need for greater clarity in the Rules on the treatment of the negotiated charge paid by the importing region to the exporting region for the purposes of determining annual aggregate revenue requirement of a TNSP?
Q49.	Would it be appropriate to extend the expiry date of clause 3.6.5(a)(5)(ii) from 1 July 2006 to 31 December 2006 to coincide with the conclusion of the Commission's review?

A45: In general, it is EnergyAustralia's view that inter-regional transmission issues are best handled at a jurisdictional level. As such, it may be more appropriate to deal with these issues through the Ministerial Council on Energy (MCE) process rather than the AEMC's review of the transmission pricing rules. However, to contribute towards the debate, EnergyAustralia offers some initial comments on the remaining questions posed by the AEMC on this subject.

EnergyAustralia is unlikely to be significantly affected by the establishment of inter-region TUoS charges, but the same could not be said for customers located in the vicinity of existing and new interconnections. Customers located near expensive interconnection assets will notice an increase in charges, if those assets are priced in the same way as the remainder of the network.

During the course of establishment of the existing pricing arrangements, an initial goal was the development of national pricing arrangements which were independent of jurisdictional boundaries. There were significant inter jurisdiction cash flows created by this approach, which led to its abandonment. The cash flows related to relative network utilisation but also reflected the age profile of assets employed by TNSPs.

Establishing a national pricing arrangement remains an important objective but this needs to be tempered with an understanding of the pricing impacts and how these might be managed.

A46: See A45.

A47: In principle, a national approach to TUoS calculation should avoid the consideration of extent of use of a network in determining inter-regional charges. This would be the preferred arrangement. However, in the interim, criteria for determining the extent of use in the Rules would complement the TUoS cost allocation process and would be a step towards uniform transmission pricing.

A48: EnergyAustralia has had no experience with the negotiation of inter regional charges. However, in line with our support for a prescriptive TUoS pricing arrangement to be retained in the Rules, EnergyAustralia would support clarity in the Rules on inter-regional payments.

A49: EnergyAustralia would support the extension of existing inter-regional arrangements until such time as the AER concludes its review. However, EnergyAustralia believes the development of national pricing arrangements and economic prices modelled on the approach in the UK will require an extended review period.

10.2 Alternative Arrangements

Q50.	Do the current, or alternative arrangements provide TNSPs with adequate incentives to invest in assets that facilitate electricity flows between adjacent jurisdictions? If not what improvements could be made?
Q51.	Should the negotiations of inter-regional payments be between TNSPs rather than jurisdictional governments?
Q52.	Should incentives/penalties be in place in the Rules to ensure that an inter-regional agreement is in place?

A50: The ACCC's review of the Regulatory Test[5] in late 2004 to include competition benefits in the analysis of proposed interconnections was a welcome step towards facilitating their development. EnergyAustralia has not been involved as a proponent of such projects but would suggest it may be premature to conclude that further steps are necessary, given the complexity and long lead times associated with such proposals.

A51: It is inevitable that jurisdictions will take an interest in inter-regional cash flows which will affect the energy prices in their area. The development of national network pricing arrangements will, for this reason, need jurisdictional agreement.

A52: Unless the Rules or another market instrument makes it mandatory, participants with competing interests will have difficulty in reaching agreement and establishing formal contractual arrangements.

EnergyAustralia would support a Rules requirement that parties establish interconnection agreements, together with sufficient guidance on their intent and content.

Whilst not part of the current review, agreements should also be mandatory between Retailers and the Distribution Networks that their customers use.

Q53.	Should the provisions of clause 3.6.5 be replaced by a modified approach to TUoS pricing more generally?

A53: Settlements residues have been disbursed since the start of the NEM, via a reduction in TUoS charges. Apart from some uncertainty caused by the variation in net TUoS charges to be reflected in customers' network bills caused by this regime, this arrangement has operated satisfactorily and the proceeds of settlement residues returned to all customers via a proportionate reduction in their TUoS charge.

In the event that an alternative means of returning settlements surpluses to customers is established, due account will need to be taken of the increase in TUoS charges and distributional effects that would result. It is likely that relaxation of the 2% cap on movement of the usage price would prove necessary.

5 Decision: Review of the Regulatory Test for Network Augmentations, Australian Competition and Consumer Commission, 11 August 2004.