30 September 1999

Mr. Michael Rawstron
General Manager Regulatory Affairs – Electricity
Australian Competition & Consumer Commission
PO Box 1199
DICKSON ACT 2602

Our ref : R-99-235

Dear Mr. Rawstron,

**APPLICATION FOR AUTHORISATION**
**APPLICATION TO VARY AN ACCESS CODE**
**NATIONAL ELECTRIICTY CODE**
**NETWORK PRICING CODE CHANGES**

We refer to the Issues Paper dated September 1999 advising that the Australian Competition & Consumer Commission ("ACCC") has received an application from the National Electricity Code Administrator Limited ("NECA") requesting variations to the National Electricity Code ("NEC") under the Trade Practices Act 1994 ("TPA") in relation to network pricing changes to implement recommendations of the Transmission and Distribution Pricing Review finalised by NECA in July 1999.

Please accept the attached document as Ergon Energy's submission on the application. In this submission Ergon Energy comments only on those issues where it has formed an opinion and on those matters where the ACCC has sought specific comment. We follow the number convention applied by the ACCC in the Issues Paper. Please note that Ergon Energy will, of course, give consideration to making further comments during any subsequent consultation process.

Ergon Energy thanks the ACCC for the opportunity to provide comment on the network pricing code changes as proposed by NECA.

Should you wish to discuss this submission in more detail please feel free to contact Darren Barlow on (07) 3228 8116.

Yours faithfully,

**Alan Millis**
**General Manager – Strategic Development**

# ERGON ENERGY

# SUBMISSION ON NETWORK PRICING CODE CHANGES

## 1.0 INTRODUCTION

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## 2.0 COMMENTS ON ACCC QUESTIONS

### 4.1.1 Existing arrangements

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

The movement of generators access from regulated to unregulated status (i.e. out of the AARR) is supported (which we understand to mean market access, not network access). However, the network is a monopoly services provider and in this context we are concerned that insufficient recognition is made of the implication of this when negotiating for access. Monopoly service providers tend not to engage in negotiation with a view to reaching a commercial solution (i.e. one that benefits both parties to the negotiation) due to the asymmetry of power and information. Therefore we doubt the efficacy of the proposal that generators negotiate in the manner proposed.

Further, we are concerned with the potential outcome of any negotiation. We assume the potential outcomes will be:

- the negotiation resulting in the generator incurring access charges and terms/conditions that are reasonable (possible although we believe unlikely); or

- Monopoly service provider abuse of power resulting in the generator being exposed to either terms or conditions for access that are unreasonable. The effect of these are unquantifiable without knowledge of the term or condition, but are likely to exhibit charges higher than would have been incurred had the market power not resided with the monopoly service provider. The effect of this is to penalise the generator (i.e. higher charges going to the NSP's bottom line).

It is therefore important that the right to negotiate for access does not result in a distortion greater than that presently existing within the system although we acknowledge the generator does not have to contract for access (to the market). In this context, we consider it important that the normal network performance requirements continue to apply to the NSP in respect of customers not specifically contracting for access. It is possible that the information required under Section 4.3 of the Issues Paper (second set of points) could assist in ensuring that the outcome of any negotiation is reasonable.

### 4.1.2 Who should pay transmission use of system charges

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

The pricing framework should be aimed at ensuring economic efficiency is maximized. This goal is jeopardized when one sector of the market is excluded from being allocated costs which reflect the provision of services to it. In this context the NECA proposal that incumbent (i.e. existing) generators be exempt from locational price signals because no TUOS is collected from them is not only against the principles of the market as espoused in clause 1.3(b)(4) and (5) of the Code but also inequitable.

An argument often advanced to support the proposal that existing generators not pay TUOS charges rests upon the assumption that imposing such a charge is inequitable (as there was no such charge in the past). This assumption is, we believe, incorrect as it implies the existing generator location adjacent to fuel sources results in both long and short run marginal costs being higher than the cost of plant located adjacent to the load, requiring little transmission. We suggest this assumption is incorrect because past planning practices considered transmission costs (and costs of losses) along with fuel and fuel transportation expenses as part of a cost minimization exercise. Mine-mouth power station developments did therefore carry the cost of associated transmission developments in the past.

We feel the historical predisposition towards locating generators near to fuel sources would not have differed had locational TUOS been levied. Therefore it is appropriate that locational TUOS be allocated to existing generators.

We are aware of the argument that existing network capital costs are "sunk" and not relevant to the dispatch of existing generation. While the levying of TUOS on new generators only will allow proper consideration of locational costs and we support the consideration of TUOS costs in the location of new generation, once the generation (and any associated network enhancements) is built, the argument about sunk costs is again relevant, for both new and old generators.

In the absence of locational TUOS assignment to existing generation sources the competitive advantage of existing generators vis a vis new generators (who are subject to locational TUOS) creates distortion of the industry cost curve and within it of the relative position of new generators on that curve. The effect of this distortion is to artificially advantage existing generators over new generators in dispatch.

The above indicates a distinction between the investment and dispatch decision. However, if network costs are to be considered and applied in new generators' investment decisions, they will inevitably need to be taken into account in their subsequent pricing and dispatch (as they will have paid, or be liable to pay TUOS charges).

Adding locational TUOS to all generators therefore results in the true relative cost of all generators being considered (i.e. economic efficiency is enhanced) because these costs require inclusion in generator bidding. The resulting ordering of a generators' position on the industry cost curve promotes more efficient (i.e. lower overall cost) generators via a lower relative position on the industry cost curve. Such an act promotes competition between generators when bidding is based upon actual relative costs creating a level playing field among generators.

We recognise the conflict between the goals of maintaining a level playing field between old and new generators for competitive purposes, and the practicality of generators operating in a short term trading environment that is principally marginal cost based. Resolution of this conflict, while preserving the appropriate economic price signal, is achievable only where sunk costs are recognised as such. The allocation of sunk costs then occurs either as an annual fixed charge per generator or assessed in advance on a CRNP type basis for charging to generators (i.e. variabilisation creates a different, although less harmful, form of distortion). Such a system allows generators to trade based upon marginal costs in the knowledge that full cost recovery requires long (not short) run marginal cost recovery, that naturally includes recovery of the sunk cost fixed charge (irrespective of the underlying allocation methodology).

One of the underlying assumptions upon which it appears the decision was made that existing generators be relieved from paying locational TUOS is that they are unable to pass this cost to consumers. This is incorrect. Generators can pass on this cost via two discrete but complementary methods, either:

- increasing average spot pool prices to their true economic cost would promote economic efficiency and remove market distortion; and/or

- passing the cost through to counterparties to the extent that the generator's sent out load is hedged (depending upon the form of International Swap Dealers' Association ["ISDA"] Agreement between counterparties).

NECA, in its acceptance of the incumbent generator argument, appears to be unaware of the hedging practices of generators. In the recent past ISDA Agreements have been subject to a locational TUOS pass through clauses which enable generators (subject to locational TUOS charges in the future) to pass through these increases to counterparties. Thus, levying locational TUOS on generators filters through to other parties to the extent the generator hedges in this way.

To conclude, recovery of TUOS from all generators (irrespective of whether it is new or old) is, in our opinion, less distortionary than the NECA Code proposal.

*Could the framework for recovering sunk costs from customers also be applied to generators?*

We believe the mechanism applied to the collection of network sunk costs (i.e. load) is equally applicable to generators and should be implemented as soon as possible as a recovery mechanism.

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

While we agree it is imperative that all future network augmentation should be undertaken on an economically efficient basis, we query whether the proposal achieves this outcome. The NECA proposal is that a form of cost/benefit analysis be undertaken in which beneficiaries of the development and those incurring cost from the development are recognised and consulted. This is not however analogous to the commercial considerations examined under normal capital investment criteria as applied by commercial entities.

A major flaw in NECA's determination is the assumption that beneficiaries will declare themselves. This is, in our opinion, most unlikely as clearly benefit accrues to all those that are able to "free ride" upon the development. The proposal is a recipe for dispute creation.

We are also uncomfortable that the Code dispute resolution procedures are adopted for the settlement of all disputes arising as these have been shown to be cumbersome and expensive.

The intent of NECA's recommendation is theoretically sound although naïve and reveals a misunderstanding of normal commercial behavior. A profit maximising firm will not volunteer information suggesting they benefit from new investment, the true extent of the benefit, or agree to pay the present value of the benefit in order to fund the project. In reality, the profit maximising firm will game this situation to prove that it does not receive benefit and thus free ride upon others.

Moreover, it is not clear that the proposals will provide a stable network pricing outcome. The benefits of an investment, even if quantifiable, will change over time as the system evolves and new generation and loads commence or existing ones exit.

*Are NECA's proposals sufficient to get market participants to reveal the extent of the benefits they will receive from a new network investment?*

No. As discussed above we do not believe the NECA proposal is practical.

*Alternatively, are the proposed new network investment arrangements likely to elicit behavior where market participants will act in a strategic manner by denying they receive benefits from new investment in the anticipation that the investment will go ahead and be paid for by other network users?*

Yes. As discussed above we believe that NECA's proposal will generate an environment where gaming investment rules will become a primary focus of Market Participant behavior. Further, the level of dispute this will generate by those Market Participants who are unjustly allocated costs will ensure, we believe, that the process of new investment approval will become so fraught with legal and regulatory risk that new network investment will be jeopardized.

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

We believe that the use of the Code dispute resolution procedure for disputes over benefit assignment (and therefore cost allocation/recovery) is unworkable. Therefore we endorse another system/scheme for settling these disputes. Amending the ACCC's powers to arbitrate in these disputes is one solution, as would be amending the Code to allow NECA to arbitrate, however we believe that neither solution is optimal. We suggest that the National Electricity Tribunal be constituted such that it acts as arbiter.

In relation to augmentation test criteria and the actual process of network planning, we note that in the new market arrangements, with freedom of entry to generation, there is likely to be less co-ordination between generation and transmission investments. This will complicate the process of planning (and acceptance for regulatory purposes) of network developments as they may be stranded (or need to be accelerated) by changes in the assumed generation developments. This highlights a need for Participant consultation and for deferral of network decisions as long as is practicable (although this may itself impact on generator decisions). As far as the demonstration of public benefits is concerned (i.e. demonstration of the need for network enhancement), it will be necessary to consider a range of generation scenarios (some of which may be mutually inconsistent) in reaching a decision. The importance of making decisions as late as possible (so generation/load developments are more certain) is clear. This process may result in more robust developments (lower risk) but not necessarily the lowest cost.

### 4.1.3 How should transmission use of system charges be levied?

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

A move to long run marginal cost as the basis for transmission network pricing will have the effect of increasing average prices in systems without spare capacity and reducing average costs in systems with spare capacity. Hence "congestion" in the system is priced under long run margin cost models. When prices rise (congestion will therefore be an issue) a signal is provided to the market that expansion (i.e. capacity increase) is required.

There may be an issue as to the definition of long run marginal cost ("LRMC"), which might need to be done on a case by case basis. For example, in the case of a line with sufficient spare capacity to meet foreseeable load/generation investments, the LRMC should not include the capital cost of augmentation. If it did, a perverse result of high price on a lightly-loaded line could arise. This essentially returns to a sort of short run marginal cost ("SRMC") pricing, although it might be possible to include a discounted capital component to reflect the cost of future investment (which will be bought forward if a new load or generator takes up some capacity and so gradually increases the capital component as the line is loaded up). A problem with this is the fact that prices would fall to SRMC immediately after completion of an enhancement – which could then have difficulty recovering its costs. The possibility of using a system like this and recovering the remainder of the regulated costs by a non-distortionary charge might address this issue.

Another question is whether the incumbent transmission network service provider can use its monopoly power (especially in elongated systems such as Queensland) to profit maximise (i.e. price at the point $1 below that economically required by a new entrant to relieve congestion on the system). Rules/regulations governing the long run marginal pricing applied by the transmission network service provider will still be required to ensure these situations do not arise.

Further, the rules should be sufficiently detailed as to ensure economic bypass is not fettered and new entrants have the ability to upgrade the existing network and receive an economic return on the capital spent without removing the revenue cap or property rights of the existing transmission network service provider. Thus the one "asset" receives two income streams, one for the unmodified existing system (i.e. the old TNSP) and another for the enhancement of capacity (i.e. to the new entrant) where in both cases the long run marginal cost is used as the basis for prices. In this instance the Pricing Regulator would need to ensure the marginal cost component of the price of the incumbent TNSP was lowered as a result of the enhancement to that of the enhancement (i.e. to encourage the TNSP to install additional capacity itself to avoid economic by-pass).

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

We do not believe that the provision of a range of values that a TNSP may select from will result in anything but profit maximising behavior. By this we mean that the TNSP will select that connection point price that will deliver to it the greatest level of revenue. Given that the TNSP will operate as a profit maximiser we do not see benefit in utilising resources to develop a range of prices for each connection point when the outcome is reasonably known. We recommend that the ACCC simply advise the TNSP of the price that will meet the Revenue Cap overall.

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

Over signaling will be evident to the extent that short and long run pricing replicate the cost of system congestion (i.e. double dipping). In the present market model, congestion pricing really only occurs on interconnectors although within regions there may be a general pool price rise as a result of generators being constrained-off. This doesn't provide any specific investment signal, however.

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

As discussed above we believe profit maximising firms will select the point within the price range that delivers maximum revenue rather than an efficient market outcome. Therefore the Code changes are inadequate.

### 4.1.4 Summary of TUOS Charges

It is not clear what is meant by the words "fixed charge" in the last two dot points under "Customer use of system cost – usage component" as it appears to conflict with the third last dot point.

In relation to the second dot point under "Customer use of system – general cost component" it is not clear that market NSPs should not pay this charge – they receive the same service, including security etc. and effectively act as proxy for customers at the other end of their interconnection.

### 4.3 Price negotiation framework and unbundling transmission and distribution charges

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

We do not believe, as suggested in the Issues Paper, that under the existing arrangements (i.e. with no recovery of negotiated discounts from other users) that networks will refuse to negotiate and so cause by-pass. Rather, the prospect of by-pass should ensure that there is a negotiation and the prospect of an impact on network return will drive that negotiation.

We recognise that this raises risk for NSPs and that some protection may be required. However, allowing full pass-on of discounts to other customers will remove the commercial discipline from the NSP's negotiations. The proposed limitations on pass-through may improve some of these disciplines.

Information asymmetry is a major impediment to a customer successfully negotiating an agreement with a monopolist. While we agree that the list of information to be provided to the customer addresses to a large degree this issue, it may still be necessary for a procedure to be developed whereby the customer may exit the negotiation and seek mediation should the monopolist negotiate in bad faith.

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

It is prima facie unjust and inequitable that those who are unable to negotiate due to a position of weakness relative to other customers and a monopoly bear the cost of another party's success. We do not agree with this as a principle. We do not disagree when a customer has an equal ability to negotiate a discount but chooses not to enter into negotiations. This however needs to be reconciled with the net public benefit of ensuring a large user remains connected to the network which (even with subsidy) reduces network charges for all. For example, if an aluminum smelter is deciding whether to close or remain open, and the later outcome relies upon a reduced transmission cost, it may prove beneficial for all customers to subsidise the smelter (via discounts) rather than face a higher average cost as a result of its closure (and the subsequent NSP need to collect all TUOS from remaining customers). We agree with differential pricing and discounts in these instances subject to the decision being made an open and transparent manner via public processes. We also accept that discounts may be negotiated where the alternative is economic by-pass of the relevant part of the network.

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

This question presupposes that there is a "correct" allocation of charges when all that can really be said is that there is a range of economically acceptable prices (marginal cost to stand-alone).

For all customers to be placed in the same bargaining position it is necessary for all information pertaining to the settlement to be publicly released. This allows others to assess the likelihood of success in negotiating and removes a level of market power exhibited by the monopolist by ensuring all customers are placed on a level playing field.

### 4.5 Embedded Generation

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

Ergon Energy supports the development of small-scale embedded generation where this provides an economic means of network augmentation or supply to distribution system customers. As the embedded generator clearly reduces the TUOS charges payable by the local NSP, we support the proposal that those savings be passed through to the embedded generation project. We believe however, that this should apply to bona fide network or customer-related or renewable energy projects, and not to larger projects which might be located within a distribution network simply to obtain that benefit. The amount passed through should be recoverable by the LNSP in the same way as it would have been if paid as TUOS.

We would be concerned if the proposed inclusion of the new arrangements in Chapter 6, in combination with the various jurisdictional derogations, meant that this change could be deferred for possibly a considerable period. We suggest that the change be located in the Code so as to become effective immediately.

## 3.0 CONCLUSION

The Transmission and Distribution Pricing Review undertaken by NECA was a major feat and represents the first post NEM commencement market design appraisal. The comments offered by Ergon Energy in this submission in no way diminish the complexity of the task faced by NECA or the difficulty it faced in reconciling competing interests. That said, we are disappointed NECA proposed in many instances merely to continue existing distortions in the market because sectoral lobbying was so intense to maintain the status quo. We welcome the ACCC's review of NECA's Final Report.