TOTAL ENVIRONMENT CENTRE INC.
LEVEL 4, 78 LIVERPOOL STREET, SYDNEY, NSW 2000
PO BOX A176, SYDNEY SOUTH 1235
Ph: 02 9261 3437 Fax 02 9261 3990
www.tec.org.au

SUBMISSION

Energy Reform Implementation Group

Issues Paper

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For further information contact:

Glyn Mather
Ph 02 9261 3437
Email glyn.mather@tec.org.au

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1. Introduction

1.1 The Energy Market Reform Program

Total Environment Centre (TEC) welcomes the establishment of the Energy Reform Implementation Group and the consequent opportunity of further examination of the reform program for the National Electricity Market (the NEM).

We have restricted our recommendations in this submission to electricity access and the NEM, in particular:

- The Rules should refer to a Demand Management (DM) Code of Practice for distribution and transmission networks, with the NSW model to be adopted as a minimum (including the protocol for disclosure of information); networks to be obligated to *implement* non-network solutions where more cost effective than augmentation. That is, it must be ensured that networks investigate and implement DM as an alternative to network augmentation where cost effective.
- Establish incentives throughout the NEM for the implementation of DM and the use of small, local generators based on alternative energies.
- Retain a revenue cap for transmission network revenue.
- Ensure equity of connection for small, alternative generators – barriers to connection currently favour large, fossil fuel generators. Appropriate value needs to be allocated to the benefits offered by such generators within transmission and distribution use of system charges.
- Provide transparency of pricing in relation to demand and constraints – end users are currently unaware of the true price of their electricity.
- Ensure networks disclose information on impending constraints in a timely manner.
- Promote a revenue cap for distribution networks since they essentially form geographic monopolies. Where a price cap is in place, generous incentives should be developed to encourage cost-effective network DM. Network service providers (NSPs) should be required to earmark a specific minimum spending level for DM: between 10% and 25% of the projected network capital expenditure should be set aside for cost-effective DM projects, on "use it or lose it" terms. Alternatively a “D” factor system could be applied, as in NSW, which is intended to promote DM by networks through the use of incentives; that is, the NSP must demonstrate that its DM implementation costs are less or equal to the avoided distribution costs before it can pass through any costs to customers.

1.2 Demand management and the NEM

Demand management (DM [1]) in all its forms must be recognised as a viable alternative to current attitudes and actions throughout the NEM because of the benefits that it delivers to consumers. The NEL Objective is set up to cater for "the long term interests of consumers"; without effective DM this is not being achieved.

A report for Energy SA[2] gives a useful list of examples of demand side management opportunities:

- energy efficiency programs
- load shifting
- load curtailment
- tariff structures and metering
- embedded generation, including fuel switching issues
- distribution network constraints, which provide opportunities for DM

The report goes on to suggest that, "Demand Side Management activities have the potential to provide a low cost alternative to generation and transmission investments, and are often the only effective short term tool for overcoming supply side and distribution system inadequacies."[3]

Economic efficiency is central to the NEM. To achieve this there must be equal emphasis on demand and supply as the basis of standard economic regulation. DM and energy efficiency must therefore be given high priority and be integrated in uniform national regulation.

1.3 Scope of this submission

Rather than directly addressing the questions posed in the issues paper, we have restricted our comments to two specific areas that we consider to have the greatest impact on greenhouse gas emissions in the context of a national energy market:

- Transmission
- Non-network solutions (demand management).

2. Transmission

2.1 Transmission regulation

Transmission network service providers (TNSPs) wield considerable market power and form natural monopolies, thus creating barriers to alternatives such as embedded generation and the range of demand management options. There is little constraint in the opposite direction (as exemplified by the fact that there is effectively one TNSP per

[1] DM in this submission can be read to include 'demand response', 'demand side management', 'demand side response', 'energy efficiency' and 'non-network solutions'. In general, DM can include both the management of peak loads and energy efficiency as a way of meeting capacity requirements most cost effectively. It includes a diverse array of activities that meet energy needs, including cogeneration, standby generation, fuel switching, interruptible customer contracts, and other load shifting mechanisms.
[2] Energy SA, *Demand Side Management – Benefits to Industry & the Community*, 2001, p 5
[3] Ibid., p 5

jurisdiction, with a handful of MNSPs). As such, obtaining greater efficiencies from their investment and operation must be a principal goal of regulation.

TEC is in favour of clear directions being set out in the Rules, to promote certainty for all stakeholders. As a general principle, matters of importance ought to be addressed within the Rules, rather than left to the discretion of the Australian Energy Regulator (AER). Light-handed regulation can lead to a lack of certainty for stakeholders. The Rules should therefore give precise guidelines to the AER in its decision-making capacity.

2.2 Network incentives

Since transmission networks are not required to invest in DM when it is cost effective, there is a strong tendency to focus purely on new infrastructure as an answer to increasing demand. This tendency can be labelled "strategic behaviour" and includes the practice of "gold-plating". Inappropriate moves to artificially increase revenue include unnecessary expansion of the regulated asset base (RAB) and over-blown demand projections. To ensure that these practices are minimised, if not eliminated, it is critical that the AER undertake meaningful and substantiated assessments of past network investment and disallow recovery of imprudent investment that should have been deferred. Prudency reviews also need to be more transparent and should include failure to undertake DM when cost effective as a reason to disallow capital expenditure.

Incentive mechanisms for the pass-through of DM costs are needed to counter the inappropriate focus on the supply-side of energy service provision and to limit inefficient over-investment in transmission infrastructure. The absence of incentive mechanisms for the implementation of demand management and other non-network solutions is resulting in inefficient, peak-demand driven transmission infrastructure investments.

The 'D-factor'[4] incentive mechanism initiated by IPART for distribution network service providers (DNSPs) has helped to spur networks into investigating and carrying out DM solutions. It enables networks to pass-through the costs of DM projects, ensuring an appropriate rate of return on this investment. More broadly, it is helping to create a viable DM provider industry that is able to respond to networks' calls for DM. The response to the D-factor incentive mechanism in NSW to date is promising, indicating that this approach is a valid means of promoting more efficient network investment.

The transparent and thorough investigation of DM alternatives to network augmentation should be made clear through the Rules to ensure that these investigations are central to the determination of proposed efficient capital expenditure by the AER.

The Australian Energy Market Commission (AEMC) Draft Proposal on transmission revenue[5] provides a mechanism for re-opening the revenue cap on transmission cost recovery for "prudent, unforeseen capital expenditure". Again, it can be difficult within the current regulatory climate to argue the prudency of DM expenditure. Furthermore, a shortfall in predicted DM savings may leave a TNSP at risk of carrying the full capital cost of an alternative (supply-side) means for meeting its reliability requirements. The eligibility of DM-related capital expenditure under this mechanism should be made

[4] Independent Pricing and Regulatory Tribunal of New South Wales, *Guidelines on the Application of the D-factor in the Tribunal's 2004 NSW Electricity Distribution Pricing Determination*, April 2005
[5] Australian Energy Market Commission, *Rule Proposal for the Regulation of Transmission Revenue*, February 2006

explicit. As a complementary measure, in the event that expected DM resources do not materialise as planned, the eligibility of capital expenditure undertaken to implement supply-side solutions where needed should also be made explicit.

We recommend also that, since TNSPs are not yet fully experienced in DM measures, the AEMC pursue the feasibility of a transitional mechanism. The aims would be to remove risk, such as by allowing TNSPs to become familiar with DM techniques for meeting time and load targets, and develop strategies for maintaining service and reliability requirements wherever DM does not meet the required targets. This could include milestones for TNSPs to develop DM implementation plans as well as exit strategies to allow alternative measures to be undertaken. Such a transitional mechanism could include procedures for the TNSP to interact with the AER in finding solutions for such situations on a case-by-case basis.

One price mechanism that would facilitate uptake of DM in the NEM would be the development of firm short and long-term prices for demand side response arrangements, which would not only make investment more attractive but would also enhance the reliability benefits of DM. It appears that the Ministerial Council on Energy (MCE) is investigating the means for establishing a short-term price process, which would be helpful. With short-term pricing forward trading would probably be enabled.

The proper implementation of tailored price mechanisms in response to interval metering (providing the meters are advanced, interactive meters) would also assist here. The Ministerial Council on Energy (MCE) has given the go-ahead for the use of "smart" meters across the NEM, but the specific type and timing has been left to the jurisdictions. This means that there is no real certainty for investors in all areas of the NEM – from generators through to retailers – and this situation needs to be clarified. Interactive meters and varied tariff plans will increase the importance of DM within the NEM as customers implement their greater range of choice, with the potential for reduction not only of the peak loads but also of base loads. This can only improve the reliability contribution of DM.

2.3. Transmission pricing

The current system of pricing has been described as:

> *regulators determine the efficient costs to provide a particular service (usually in a forward looking manner – for example, for the next five years) and this generates the maximum allowable revenue that a business can generate. This model is known as the building blocks approach to price regulation. Very significantly, these efficient costs include the costs on and of capital, in addition to operational expenditures.*
> *Based on the maximum allowable revenue, prices of individual services are then calculated by using, for example, forecasted demand or the quantities observed in previous periods. That is, prices are linked to costs through the maximum allowable revenue and the demand function.'*[6]

[6] Breunig, R., Stacey, S., Hornby, J., Menezes, F. M., *The Australian National University Working Papers in Regulatory Economics – Price Regulation in Australia: How consistent has it been?* Working Paper 2005 No. 1, Australian Centre of Regulatory Economics & The Australian National University, 2005, p 4

For an efficient system under the NEM Objective, there should be price signals at all levels, including transmission. In the broad framework of prescription (with only limited discretion for TNSPs and the AER), dynamic efficiency would better suit the NEM Objective, with the potential for price signals. If a methodology for time-of-use charges could be devised for the transmission sector, DM approaches could be better utilised to respond accordingly. A more prescribed system for pricing could also reduce variation across jurisdictions, and aid in TNSPs allocating prices more efficiently.

These considerations would not be addressed by applying fixed charges, which necessitate instead some form of pricing that includes the demand side in the equation. Sustainability requires an approach that has it eye on the long term – as the NEL Objective requires.

A pricing methodology needs to be developed by the AEMC to properly account for: avoided costs of network augmentation, avoided costs of greenhouse gas emissions, accurate costing of connection to the network, reduced requirement for generation, and contributions to reliability generally, with pricing principles to allow for these costs. This methodology should incorporate the benefits of both alternative technologies and DM, and should be supported by a comprehensive set of case studies.

2.4. Connection costs

The current system allows for new generators to pay only shallow connection costs, that is, to cover the costs of assets directly required by a new connection. This applies equally to large, remote generators as to those situated closer to load points.

This is the theory. In practice, however, it appears that smaller, local generators may be charged for upgrades to the network, where the extra load necessitates some augmentation of the system beyond those required specifically for the new connection (deep connection costs). This contravenes the general principle of paying shallow costs and, moreover, the spirit of "open access" the NEM is based on. It is more of a problem in the distribution network, but still poses a challenge for transmission. Thus a major disincentive for consideration of embedded generation alternatives is financial, not only due to the risk of paying deep connection costs but also because it may be regarded unfavourably TNSPs. DG may reduce the need for transmission network services, which can be perceived as threatening the revenue base.

A balance needs to be struck to allow smaller generators easy access to the system, while providing for generators remote from the load points to contribute to the true costs of providing transmission network services.

Any solution should be prescribed in the Rules, to promote clarity and equity of access.

The most satisfactory and equitable arrangement – to honour the spirit of open access – would be for deep connection costs to apply only to large generators entering the system. If the NEM is truly designed to assist the entry of a variety of types of energy and participants, then small and/or local generators should not be expected to foot the bill for supporting large, remote generators which are usually powered by fossil fuels. Thus prescriptions could be designed whereby such generators could be expected to contribute to the costs of augmentation – of course, after non-network solutions have been investigated and implemented where cost-effective.

Existing large, remote generators must contribute in some fashion if a deep connection methodology is adopted. Those of this type would have already benefited from the shallow connection approach in the past. It is also manifestly unreasonable to force a small, local generator to pay the full extent of deep connection costs when it may only be adding a minor extra load to the network.

2.5. Transmission Use of System (TUOS) charges

Transmission Use of System (TUoS) rebates are intended to recompense local generators requiring lower use of the transmission network – and hence lower usage charges for DNSPs – by virtue of location closer to load points. However, embedded generation (or DG) offers a range of benefits not entirely reflected in the current method of calculating avoided TUoS rebates. In particular, embedded generation offers value to a TNSP through its potential to enable the deferral of new transmission augmentation. Embedded generation also offers the benefit of reducing environmentally damaging greenhouse gas emissions, the cost of which is currently externalised in the NEM. The value of TUoS rebates should include the value of deferral of new network augmentations as well as the following:

- Annual operating cost of the deferred augmentation
- Total annual net cost of servicing the capital expenditure of the deferred augmentation including:
    - financing charges
    - capital depreciation.

As stated by the AEMC, "It follows that to the extent embedded generators help avoid or delay transmission augmentation, they receive a rebate based on the long run marginal value of their contribution."[7] Including the full value of deferral of network augmentations in the calculation of TUoS rebates would provide more accurate price signals across the NEM. Such an approach would also encourage TNSPs to more fully utilise the benefits of non-network solutions, by making the true costs – and long run costs – more transparent since it also presents an opportunity for recognition of long-term effects.

If the connection into the network – or DSM or other non-network options – contributes to the cost-effectiveness or reliability of the system in some way, then there should be payment in kind from the TNSP via rebates since it is to the financial benefit of the TNSP in the long term.

3. Non-network solutions

3.1 Changing the focus from supply to demand

The current transmission network Rules are inappropriately focused on the supply of electricity at the expense of a focus on the provision of energy services, including demand side or other non-network approaches. This focus has resulted in:

- enormous and unnecessary costs of inefficient network investment;
- the erasure of accurate price signals at multiple points throughout the NEM, including transmission networks;

[7] Australian Energy Market Commission, *Review of the Electricity Transmission Revenue and Pricing Rules – Transmission Pricing: Issues Paper*, November 2005, p 29

- barriers to distributed generators and demand management (DM) providers; and,
- a greenhouse gas emission intense electricity system that brings with it a disproportionate risk of future carbon liabilities.

An efficient, cost-effective electricity supply system should make allowance for solutions other than those that rely entire on network-driven solutions. Demand management in its various forms can indeed be more cost effective, and hence more efficient, thus meeting the NEL objective. Non-network solutions therefore should be given explicit consideration within the Rules.

A major issue is the planning processes that TNSPs are required to undertake under the Rules. Currently, TNSPs are not required to solicit proposals for alternative non-network solutions before deciding to augment their networks. This creates a natural barrier for cost-effective non-network solutions and forecloses on the potential for networks to operate more efficiently by avoiding unnecessary or premature network augmentations, and thereby create savings for consumers.

The Energy Networks Association described demand management approaches[8] as including load management measures; distributed generation (for instance for renewable energy); power factor correction; and fuel substitution. They noted that these, "approaches may provide alternatives to increased energy supply or augmentation, through shifting or reducing customer demand, actions that alter the level or pattern of energy consumption, the energy source, or the use of the distribution network." The ENA also pointed out that there is an emerging market for demand management.

Before TNSPs undertake major network augmentations, they should be required to solicit proposals for alternative non-network solutions. This would involve clear protocols for information disclosure, specification of constraints, requests for proposals, and evaluation of proposals. To facilitate this process, the AEMC and the AER should promote a comprehensive approach through mandatory DM Codes of Practice for network service providers. This would be a key step in facilitating a DM services market. Furthermore, recognising that transaction costs of participating in a request for proposal process would be very high for many small DM opportunities, the AEMC should also promote standing offers for small DM services.

As the AEMC has stated[9] regarding the development of demand management and other energy sources, that by utilising these:

> *transmission can avoid the need for, or can itself be avoided by, the development of local generation, DSM and non-electricity options. Therefore, transmission regulation and pricing should ensure transmission does not `crowd out' alternatives. The Commission considers it important for transmission regulatory arrangements to be structured in a way that ensures that there is an appropriate opportunity for alternatives.*

[8] Energy Networks Association, *Submission to the Productivity Commission: Energy Efficiency – Response to Draft Report*, 27 May 2005, p 4
[9] Australian Energy Market Commission, *Review of the Electricity Transmission Revenue and Pricing Rules – Transmission Pricing: Issues Paper*, November 2005, p 32

Although in principle it is suggested in the Rules that TNSPs investigate non-network alternatives to postponement or augmentation, they are not **obliged** to do so, nor are they required to implement them after investigation if they are found to be cost effective. There should be an obligation imposed on TNSPs to implement alternatives where cost effective. If they do not do so, then any such augmentation works should not be included in the regulated asset base and consequently should not flow on to pricing.

Negotiation of DM provision, if at all, is often carried out through a request for proposals process, in which both transaction costs and risks for DM service providers can be high. A similar problem is embedded in the system for local generation and alternative energy sources, which are often developed by smaller companies than the monopoly TNSPs. The introduction of the standard offer is one means of reducing these costs and uncertainties, thereby facilitating the capture of demand reduction opportunities that may arise in response to forecast network congestion.

"Standard offers specify the conditions for the provision of demand in advance. Standard offers are usually made on fixed prices, take it or leave it, first come first served basis."[10] They support the development of the DM services market by reducing risks of both negotiating with networks and of guaranteeing load reductions within the spot market. Standard offers could also provide the means for networks to capture opportunities for demand reduction that may arise several years prior to going to the market for non-network solutions that would otherwise be lost.

Economic incentives are urgently needed to ensure that TNSPs consider non-network solutions before augmenting their networks.

Earmarking a percentage of network spending for DM:

One way of ensuring that networks undertake DM is for regulators to earmark a specific minimum spending level for DM by networks. Given the large technical and economic potential for DM, between 10% and 25% of the projected network capital expenditure should be specifically earmarked for cost-effective DM projects. This funding should be allowed only on "use it or lose it" terms, and could step up from an initial small percentage, increasing as networks become more adept at facilitating DM, then gradually reducing as the potential for DM is utilised.

Clarifying the circumstances in which DM investment can be claimed:

Several network providers have rightly noted that there is a lack of clarity regarding the recovery of DM spending by regulators. Consultants contracted by TransGrid have argued that uncertainty in the treatment of DM by the ACCC may have deterred them from selecting that option: "Any uncertainty as to the regulatory treatment of DSM-related expenditure by TNSPs has the potential to undermine the practical consideration of such alternatives."[11] Thus there needs to be a proper, considered scheme for treatment of such expenditure when determining acceptable revenue and assessing revenue assets bases.

[10] Department of Energy, Utilities and Sustainability, *Demand Management for Electricity Distributors – NSW Code of Practice*, September 2004, p 21
[11] NERA, *Augmentation of Supply to the Western Area: Preliminary Cost Effectiveness Analysis*, May 2003, p 36

The national regulator should therefore clearly set out the circumstances in which networks can recover the costs of implementing DM. To encourage TNSPs to undertake cost-effective expenditure on non-network solutions there is clearly a need to provide certainty as to the way in which those expenditures will be treated and the rate of return that those expenditures could be expected to deliver.

Incentive mechanism for DM:

What has been applied to some effect in NSW with distribution networks under a price cap is the use of the D-factor. This is essentially an incentive arrangement via IPART for DNSPs to promote the consideration of DM in network planning, with the requirement that, "the DNSPs must demonstrate to the Tribunal that its demand management implementation costs are less or equal to the avoided distribution costs before it can pass through any costs to customers."[12] A similar, but more limited, principle could be applied at a transmission level under a revenue cap. The AER could allow the TNSP to earn extra revenue of a value up to the specified costs of DM implementation. The potential for an increase in price by passing through costs to customers would be offset by the long-term benefits to all stakeholders of increased realisation of DM potential and the encouragement of greater network familiarity with DM.

3.2 Disclosure of information

The annual public disclosure of information on emerging network constraints is essential to the development of non-network responses to these constraints. Information presented both in tables and in map form is necessary to engage non-network providers. To encourage the uptake of cost-effective non-network alternatives to transmission augmentation, such information should be required of TNSPs. The AEMC should investigate the benefits of annual, public disclosure protocols on emerging network constraints.

Disclosure of information is fundamental to transparency and certainty of decision making, and it relies not on quantity but quality. To date, lack of information has proved a significant barrier within the NEM, both in terms of accountability of the regulator and restriction of entry by competitors (such as DM providers and embedded generators). A transparent process will provide greater certainty for all stakeholders (regulator, TNSPs and consumers) as well as potential investors. NSPs should also provide information on their expenditure on demand management, alongside opportunities they have investigated and the potential value of deferrals of augmentation.

A useful model here is the Disclosure Protocol from the NSW Demand Management Code of Practice[13]. The purpose of such a protocol is presented as:

> *To inform the market in a timely manner, regular public reports on the status of the network are required. A standardised Disclosure Protocol is intended to ensure*

[12] Independent Pricing and Regulatory Tribunal of New South Wales, *Guidelines on the Application of the D-factor in the Tribunal's 2004 NSW Electricity Distribution Pricing Determination*, April 2005, p 1

[13] Department of Energy, Utilities and Sustainability, *Demand Management for Electricity Distributors – NSW Code of Practice,* September 2004; the Disclosure Protocol is on pp11-14

> *that distributors provide all necessary information in a clear and consistent form, without wasting effort in providing unnecessary information.*[14]

The protocol includes features such as planning guidelines, for describing the basis for load forecasts and describing the system planning guidelines. It includes pro forma spreadsheets, requests for maps and summary table requests to assist with clarity of presentation and so there is some standardisation of the information lodged.

The Rules need to refer to guidelines for reporting developed by the AER, to refer to financial statements and applications for determinations.

All TNSPs (and in the future distribution and retail businesses) need to publicly provide clear information on areas facing constraints – or predicted to do so – in a reasonable timeframe (5, 10 and 15 years ahead) to allow DM providers to offer alternatives to augmentation. Such information should be required in order to encourage the uptake of cost-effective non-network alternatives to network augmentation and to ensure least-cost provision for consumers and an efficient NEM. Lack of quality information can inhibit new entrants to the market.

3.3 NEMMCO intervention

To date, the contribution DM can make has not been explicitly acknowledged within the NEM. For instance, direct load shedding arrangements with large end users have the potential for significantly easing constraints during critical peak periods. NEMMCO has the power to intervene in this situation and can make arrangements in advance of a perceived constraint. As an independent body, it is appropriate for NEMMCO to be able to institute these kinds of provisions. The efficiency benefits – and reliability of supply – outweigh any reasonable payments made to such consumers.

NEMMCO's powers could be enhanced by the development of a methodology by the AEMC for assessment of the reliability impacts of DM (and other network and non-network solutions) at an appropriate level of accuracy. These reliability impacts should also be explicitly incorporated into the assessment of capital and operational expenditure.

[14] Department of Energy, Utilities and Sustainability, *Demand Management for Electricity Distributors – NSW Code of Practice,* September 2004, p 11